UNION GAS LIMITED

EXHIBIT LIST

ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF an Application by Union Gas Limited, pursuant to section 36(1) of the *Ontario Energy Board Act*, *1998*, for an order or orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas as of January 1, 2013.

APPLICATION

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

2. Union conducts both an integrated natural gas utility business that combines the operations of distributing, transmitting and storing natural gas, and a non-utility storage business.

3. Union hereby applies to the Ontario Energy Board ("Board"), pursuant to section 36 of the *Ontario Energy Board Act*, *1998* (the "Act") for an order or orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas effective January 1, 2013.

4. Union applies for an order fixing reference prices in determining amounts to be recorded in deferral accounts, for an order necessary to reflect such new reference prices in Union's rates and other charges.

5. Union applies for approval of an accounting order to establish the Energy Technology and Innovation Canada deferral account.

6. Union also applies for an order terminating, effective January 1, 2013, certain deferral accounts, following final disposition of any 2012 balances therein, as follows:
   - Late Payment Penalty Litigation (No. 179-113)
   - Harmonized Sales Tax (No. 179-124)

7. Union also applies for an order modifying the terms and conditions of certain deferral accounts as follows:
   - Short-term Storage and Other Balancing Services (No. 179-70)
   - Average Use Per Customer (No. 179-118)
   - Inventory Revaluation Account (No. 179-109)

8. Union applies for approval, under Section 2.0 of certain Undertakings given by Union to Lieutenant Governor in Council, to continue to sell gas to consumers.

9. Union requests that the Board issue an order to enable the rates established as a result of this application to become effective January 1, 2013, notwithstanding that the Board's Decision with Reasons approving or fixing these rates and other charges may not be delivered until after that date.

10. Union also applies to the Board 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 is supported by written evidence that will be filed with the Board and may be amended from time to time 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
Suite 3000, Maritime Life Tower
P.O. Box 270
Toronto Dominion Centre
Toronto, Ontario
M5K 1N2

Attention:	Crawford Smith
Telephone:	(416) 865-8209
Fax:	(416) 865-7380

DATED November 10, 2011.

UNION GAS LIMITED

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Chris Ripley
Manager, Regulatory Applications

UNION GAS LIMITED

SPECIFIC APPROVALS REQUESTED – PHASE I

1. Approval to charge rates effective January 1, 2013 to recover a $ 71.4 million delivery-related revenue deficiency (described at Exhibit F3, Tab 1, Schedule 1).
2. Approval of Union's proposed change in capital structure, increasing Union's common equity component from 36% to 40% (described at Exhibit E1, Tab 1).
3. Approval to adopt the Board's revised formula (EB-2009-0084) for return on equity (Described at Exhibit F1, Tab1).
4. Approval to adopt US GAAP for rate making purposes (described in Exhibit A2, Tab 4).
5. Approval to change the methodology used to calculate weather normal to a 20-year declining trend methodology (described at Exhibit C1, Tab 5).
6. Approval to update bad debt expense as part of the Quarterly Rate Adjustment Mechanism process (described at Exhibit D1, Tab 2, p. 2).
7. Approval of the change in the provision for depreciation, amortization and depletion as recommended by Foster Associates, Inc. (described at Exhibit D1, Tab 6).
8. Approval to recover the costs of Union's community investments (described at Exhibit D1, Tab 8).
9. Approval of the change to the system integrity space requirement included in delivery rates (described at Exhibit D1, Tab 9).

10. Approval of funding for the Energy Technology and Innovation Canada program (described at Exhibit D1, Tab 10).

11. Approval to continue to sell gas to consumers.

UNION GAS LIMITED

SPECIFIC APPROVALS REQUESTED – PHASE II

1. Approval of the proposed Cost Allocation Study methodology changes (described at Exhibit G1, Tab 1):
    a. To change the methodology used to functionalize, classify and allocate the cost of assets at the Oil Spring East storage pool.
    b. To change the methodology used to allocate the cost of Tecumseh metering and regulating equipment at the Dawn facility.
    c. To change the methodology used to allocate the cost of system integrity.
    d. To change the methodology used to allocate North distribution customer station plant.
    e. To change the methodology used to classify and allocate distribution maintenance O&M (meter and regulator repairs).
    f. To change the methodology used to allocate distribution maintenance O&M (equipment on customer premises).
    g. To change the methodology used to classify and allocate purchase production general plant.
2. Approval of the methodology used to allocate the cost of the following new services (described at Exhibit G1, Tab 1):
    a. Dawn to Dawn-TCPL

b. Dawn to Dawn-Vector

c. M12 Firm All Day (F24-T)

3. Approval of the rates proposed in Exhibit H3, Tab 2 (described at H1, Tab 1)

4. Approval of the following specific Rate Design proposals:

    a. Approval to decrease the volume breakpoint between small volume general service rates M1 and 01 and large volume general service rates M2 and 10 to 5,000 m^3 a year (described at Exhibit H1, Tab 1).

    b. Approval for harmonization of general service rate structures between North and South operating areas (described at Exhibit H1, Tab 1).

    c. Approval to decrease eligibility for the M4 and M5A rate classes to a daily contracted demand of 2,400 m^3 and a minimum annual volume of 350,000 m^3 (described at Exhibit H1, Tab 1).

    d. Approval for an M4 interruptible service offering (described at Exhibit H1, Tab 1).

    e. Approval to decrease eligibility for the M7 rate class to a combined firm, interruptible and seasonal daily contract demand of 60,000 m^3 (described at Exhibit H1, Tab 1).

    f. Approval to decrease T1 annual eligible volume to 2,500,000 m^3 (described at Exhibit H1, Tab 1).

    g. Approval for a T2 large market rate class service offering (described at Exhibit H1, Tab 1).

h. Approval to modify the fuel ratio design for the Dawn to Dawn-Vector transportation service to recover UFG transportation activity in the winter period (described at Exhibit H1, Tab 1).

5. Approval of Union's response to the Board directive to review the M12 and C1 rate-making methodology (described at Exhibit H1, Tab 1).
6. Approval to modify the Rate M1 and Rate M2 rate schedules to set the additional meter charge equal to the Monthly Customer Charge approved for each of the rate classes (described at Exhibit H1, Tab 1).
7. Approval of modification to Schedule "C" of the M12 rates schedule to clarify the applicability of the VT1 Easterly, VT3 Westerly and M12-X Westerly monthly fuel ratios and fuel rates (described at Exhibit H1, Tab 1).
8. Approval of the methodology used to allocate costs and set rates for the Kirkwall-Dawn westerly service.
9. Approval to add the F24-T service to the C1 rate schedule (described at Exhibit H1, Tab 1).
10. Approval of modification to the M12, M13, M16, and C1 rate schedules including Schedule A, Schedule A-2013 and Schedule C (described at Exhibit H1, Tab 1 and Tab 2).
11. Approval to update the utility/non-utility allocator used to calculate margin sharing for short-term storage services to 59:41 to reflect the updated cost study.

12. Approval of changes to the Distributor Consolidated Billing fee to $0.57 per month per customer (described at Exhibit H1, Tab 3).

13. Approval to close the following deferral accounts after 2012 year-end balances are disposed of (described at Exhibit H1, Tab 4):

    a. Late Payment Penalty Litigation (No. 179-113)

    b. Harmonized Sales Tax (No. 179-124)

14. Approval to modify the wording of the following deferral accounts (described at Exhibit H1, Tab 4):

    a. Short-term Storage and Other Balancing Services (No. 179-70)

    b. Average Use Per Customer (No. 179-118)

    c. Inventory Revaluation Account (No. 179-109)

15. Approval to create the following deferral account:

    a. Energy Technology and Innovation Canada (described at Exhibit D1, Tab 10)

Union Gas Limited
2013 Rates
EB-2011-0210
Final Issues List

B. Rate Base

1. Is Union's forecast level of capital spending in 2013 appropriate?

2. Are the proposed updates to Union's lead/lag study appropriate?

3. Is Union's proposal to terminate reporting on new business-related directives from prior facility projects appropriate?

4. Is the proposed Test Year Rate Base appropriate?

5. Is the proposed working capital allowance appropriate?

6. Are the methods proposed by Union to allocate the cost and use of capital assets between regulated and non-regulated activities appropriate, and are the proposed allocations to the regulated business appropriate for the Test Year?

7. Do Union's Asset Condition Assessment information and Investment Planning Process appropriately address the condition of the distribution system assets and support the OM&A and capital expenditures proposed for the Test Year?

8. Is the allocation of capital expenditures between utility and non-utility ("unregulated") operations appropriate?

C. Operating Revenues

1. Is Union's general service demand forecast appropriate?

2. What is the appropriate methodology to be used to forecast degree days for the Test Year?

3. Is the 2013 Contract Customer Demand forecast appropriate?

4. Is the 2013 S&T forecast appropriate?

5. Is the proposed amount for Test Year Other Revenues, including the methodologies used to cost and price those services, appropriate?

6. Has Union levied proper charges and allocations to non-regulated businesses and affiliates, and provided proper credit for those charges and allocations in calculating revenue requirement to be recovered from regulated ratepayers?

D. Cost of Service

1. Is the 2013 O&M budget appropriate?

2. Are the 2013 affiliate charges appropriate?

3. Has Union complied with the Affiliate Relationships Code (“ARC”) and the Board's "three prong test" (as described by the Board in the E.B.R.O. 493/494 Decision with Reasons)?

4. Are the provisions for depreciation, amortization and depletion proposed in the 2011 Depreciation Study appropriate?

5. Are the changes to unaccounted for gas appropriate?

6. Is the proposed community investment funding appropriate?

7. Is the proposed Energy Technology Innovation Canada program funding appropriate?

8. Is the forecast of Employee Future Benefit costs which will be incurred under USGAAP appropriate?

9. Are the Test Year Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels, appropriate?

10. Are the amounts proposed for capital and property taxes appropriate?

11. Is the amount proposed for income taxes, including the methodology, appropriate?

12. Is the proposal to update the bad debt expense as part of the Quarterly Rate Adjustment Mechanism ("QRAM") process appropriate?

13. Is the proposal to continue to adjust the unaccounted for gas, company used gas and gas inventory for resale costs as part of the QRAM process appropriate?

14. Is the gas supply plan for 2013 appropriate?

15. Is the allocation of O&M costs between utility and non-utility operations appropriate?

16. Is the proposed system integrity space value and its allocation for 2013 appropriate?

17. Is the proposed Parkway commitment for direct purchase customers appropriate?

18. Is the existing Parkway obligated delivery requirement for direct purchase customers appropriate?

E. Cost of Capital

1. Is the forecast of the cost of debt for the Test Year, including the mix of short and long term debt and preference shares, and the rates and calculation methodologies for each, appropriate?

2. Is the proposed change in capital structure increasing Union's deemed common equity component from 36% to 40% appropriate?

3. Is the proposal to use the Board's formula to calculate return on equity appropriate?

F. Revenue Requirement

1. Are the revenue requirement and revenue deficiency or sufficiency for the Test Year calculated correctly?

2. Is the overall change in revenue requirement reasonable given the impact on consumers?

G. Cost Allocation

1. Is Union's utility Cost Allocation Study, including the methodologies and judgments used and the proposed application of that study with respect to Test Year rates, appropriate?

2. Are the Cost Allocation Study methodology changes to the allocation of Oil Springs East costs appropriate?

3. Are the Cost Allocation Study methodology changes to the allocation of Tecumseh metering and regulating costs appropriate?

4. Is the Cost Allocation Study methodology to allocate the cost of system integrity appropriate?

5. Are the Cost Allocation Study methodology changes to allocate the cost of North distribution customer station plant appropriate?

6. Are the Cost Allocation Study methodology changes to classify and allocate the cost of distribution maintenance O&M (meter and regulator repairs) appropriate?

7. Are the Cost Allocation Study methodology changes to allocate the cost of distribution maintenance O&M (equipment on customer premises) appropriate?

8. Are the Cost Allocation Study methodology changes to classify and allocate the cost of purchase production general plant appropriate?

9. Is the Cost Allocation Study methodology to allocate the cost of the Dawn to Dawn-TCPL, Dawn to Dawn-Vector and M12 F24-T services appropriate?

10. Should the cost allocation methodology be modified to separate Parkway Station metering and compression costs and Kirkwall station metering costs from Dawn Trafalgar Easterly costs?

11. Is the allocation of all Dawn Trafalgar Easterly costs, including metering and compression costs, based on commodity-kilometres appropriate?

H. Rate Design

1. Are the rates proposed in Exhibit H just and reasonable?

2. Is Union's response to the Board directive to review the M12 and C1 ratemaking methodology appropriate?

3. Is the proposal to lower the breakpoint between small and large volume general service customers to 5,000 M3 per year effective January 1, 2014 appropriate?

4. Is the proposal to harmonize the general service rate structures between the North and South operating areas effective January 1, 2014 appropriate?

5. Is the proposal to lower the eligibility for the M4 and M5A rate classes to a daily contracted demand of 2,400 M3 and a minimum annual volume of 350,000 M3 effective January 1, 2014 appropriate?

6. Is the introduction of an M4 interruptible service offering effective January 1, 2014 appropriate?

7. Is the proposal to lower the eligibility for the M7 rate class to a combined firm, interruptible and seasonal daily contract demand of 60,000 M3 effective January 1, 2014 appropriate?

8. Is the splitting of T1 into two rate classes effective January 1, 2013 appropriate?

9. Is recovering UFG on transportation activity in the winter months for the Dawn to Dawn-Vector transportation service appropriate?

10. Is the proposal to modify the M1 and M2 rate schedules appropriate?

11. Is the proposal to modify the M12, M13, M16 and C1 rate schedules including Schedule A, Schedule A-2013 and Schedule C appropriate?

12. Are the proposed changes to the Distributor Consolidated Billing fee to $0.57 per month per customer appropriate?

13. Are the proposed changes to the Gas Supply Administration Fee appropriate?

14. Are rate mitigation measures required to address the rate impacts on some customers as a result of the proposed January 1, 2014 rate design proposals?

15. Is the proposal to change the rate design for services originating at Kirkwall to eliminate Kirkwall measuring and regulating costs appropriate?

DV. Deferral and Variance Accounts

1. Are Union's proposed and existing deferral and variance accounts appropriate?

2. Should deferral accounts for transmission-related transactional services that were eliminated in the EB-2007-0606 incentive ratemaking proceeding be re-established?

3. Is the proposal to eliminate the Late Payment Penalty Litigation (No. 179-113) and the Harmonized Sales Tax (No. 179-124) deferral accounts appropriate?

4. Is the proposal to modify the wording of the Short-term Storage and Other Balancing Services (No. 179-70), Average Use Per Customer (No. 179-

118), and the Inventory Revaluation Account (No. 179-109) deferral accounts appropriate?

O. Other Issues

1. Has Union responded appropriately to all relevant Board directions from previous proceedings?

2. Are Union's economic and business planning assumptions for the Test Year appropriate?

3. Is service quality, based on the Board specified performance indicators acceptable?

4. Are sustainable efficiency improvements (or efficiency gains) achieved under incentive regulation reflected in Union's CoS estimates?

5. Are the forecasts of Natural Gas Market Conditions in 2013 and beyond and the impacts on Union, including turnback and mitigation actions by Union, appropriate?

6. Are Union’s customer service policies (including security deposits, late payment penalty, etc.) compatible with Board directives?

7. Have all impacts of the conversion of regulatory and financial accounting from CGAAP to USGAAP been identified, and reflected in the appropriate manner in the Application, the revenue requirement for the Test Year, and the proposed rates?

UNION GAS LIMITED

Accounting Entries for
Short-term Storage and Other Balancing Services
Deferral Account No. 179-70

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No. 570 Storage and Transportation Revenue
Credit	-	Account No. 179-70 Other Deferred Charges - Short-term Storage and Other Balancing Services

To record, as a debit (credit) in Deferral Account No. 179-70 the difference between actual net revenues for 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 net revenue forecast for these services as approved by the Board for ratemaking purposes.

Debit	-	Account No.179-70 Other Deferred Charges - Short-term Storage and Other Balancing Services
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-70, interest on the balance in Deferral Account No. 179-70. Simple interest will be computed monthly upon finalization of the year end balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

UNION GAS LIMITED

Accounting Entries for
Lost Revenue Adjustment Mechanism
Deferral Account No. 179-75

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No.179-75 Other Deferred Charges - Lost Revenue Adjustment Mechanism
Credit	-	Account No. 529 Other Sales

To record, as a debit (credit) in Deferral Account No. 179-75, the difference between actual margin reductions related to Union's DSM plans and the margin reduction included in gas delivery rates as approved by the Board.

Debit	-	Income Account No. 179-75 Other Deferred Charges - Lost Revenue Adjustment Mechanism
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-75, interest expense on the balance in Deferral Account No. 179-75. Simple interest will be computed monthly upon finalization of the year end balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

UNION GAS LIMITED

Accounting Entries for
TCPL Tolls and Fuel – Northern and Eastern Operations Area
Deferral Account No. 179-100

This account is applicable to the Northern and Eastern Operations of Union Gas Limited. Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit - Account No.179-100
Other Deferred Charges - TCPL Tolls and Fuel – Northern and Eastern Operations Area

Credit - Account No. 623
Cost of Gas

To record, as a debit (credit) in Deferral Account No. 179-100, the difference in the costs between the actual per unit TCPL tolls and associated fuel and the forecast per unit TCPL tolls and associated fuel costs included in the rates as approved by the Board.

Debit - Account No. 623
Cost of Gas

Credit - Account No.179-100
Other Deferred Charges - TCPL Tolls and Fuel – Northern and Eastern Operations Area

To record, as a credit (debit) in Deferral Account No. 179-100, the benefit from the temporary assignment of unutilized capacity under Union's TCPL transportation contracts to the Northern and Eastern Operations Area. The benefit will be equal to the recovery of pipeline demand charges and other charges resulting from the temporary assignment of unutilized capacity that have been included in gas sales rates.

Debit - Account No. 179-100
Other Deferred Charges - TCPL Tolls and Fuel – Northern and Eastern Operations Area

Credit - Account No. 623
Cost of Gas

To record, as a debit (credit) in Deferral Account No. 179-100 charges that result from the Limited Balancing Agreement with TCPL.

Debit - Account No. 500
Sales Revenue

Credit - Account No. 179-100
Other Deferred Charges - TCPL Tolls and Fuel – Northern and Eastern Operations Area

To record, as a credit (debit) in Deferral Account No. 179-100 revenue from T-Service customers for load balancing service resulting from the Limited Balancing Agreement with TCPL.

Debit	-	Account No. 179-100 Other Deferred Charges - TCPL Tolls and Fuel – Northern and Eastern Operations Area
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-100 interest expense on the balance in Deferral Account No. 179-100. Simple interest will be computed monthly on the opening balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

UNION GAS LIMITED

Accounting Entries for
Unbundled Services Unauthorized Storage Overrun
Deferral Account No. 179-103

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A, prescribed under the Ontario Energy Board Act.

Debit	-	Account No.571 Storage Revenue
Credit	-	Account No. 179-103 Other Deferred Charges – Unbundled Services Unauthorized Storage Overrun

To record as a credit (debit) in Deferral Account No. 179-103 any unauthorized storage overrun charges incurred by customers electing unbundled service.

Debit	-	Account No. 179-103 Other Deferred Charges – Unbundled Services Unauthorized Storage Overrun
Credit	-	Account No. 323 Other Interest Expense

To record as a debit (credit) in Deferral Account No. 179-103, interest on the balance in Deferral Account No. 179-103. Simple interest will be computed on the monthly opening balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

UNION GAS LIMITED

Accounting Entries for
North Purchase Gas Variance Account
Deferral Account No. 179-105

This account is applicable to the Northern and Eastern Operations area of Union Gas Limited. Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No. 179-105 Other Deferred Charges – North Purchase Gas Variance Account
Credit	-	Account No. 623 Cost of Gas

To record, as a debit (credit) in Deferral Account No. 179-105, the difference between the unit cost of gas purchased each month for the Northern and Eastern Operations area and the unit cost of gas included in the gas sales rates as approved by the Board, including the difference between the actual heat content of the gas purchased and the forecast heat content included in gas sales rates.

Debit	-	Account No. 179-105 Other Deferred Charges - North Purchase Gas Variance Account
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-105, interest expense on the balance in Deferral Account No. 179-105. Simple interest will be computed monthly on the opening balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

UNION GAS LIMITED

Accounting Entries for
South Purchase Gas Variance Account
Deferral Account No. 179-106

This account is applicable to the Southern Operations area of Union Gas Limited. Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No. 179-106 Other Deferred Charges – South Purchase Gas Variance Account
Credit	-	Account No. 623 Cost of Gas

To record, as a debit (credit) in Deferral Account No. 179-106, the difference between the unit cost of gas purchased each month for the Southern Operations and the unit cost of gas included in the gas sales rates as approved by the Board, including the difference between the actual heat content of the gas purchased and the forecast heat content included in gas sales rates.

Debit	-	Account No. 179-106 Other Deferred Charges - South Purchase Gas Variance Account
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-106, interest expense on the balance in Deferral Account No. 179-106. Simple interest will be computed monthly on the opening balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

UNION GAS LIMITED

Accounting Entries for
Spot Gas Variance Account
Deferral Account No. 179-107

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit - Account No. 179-107
Other Deferred Charges –Spot Gas Variance Account

Credit - Account No. 623
Cost of Gas

To record, as a debit (credit) in Deferral Account No. 179-107, the difference between the unit cost of spot gas purchased each month and the unit cost of gas included in the gas sales rates as approved by the Board on the spot volumes purchased in excess of planned purchases.

Debit - Account No. 623
Cost of Gas

Credit - Account No. 179-107
Other Deferred Charges –Spot Gas Variance Account

To record, as a credit (debit) in Deferral Account No. 179-107, the approved gas supply charges recovered through the delivery component of rates.

Debit - Account No. 179-107
Other Deferred Charges – Spot Gas Variance Account

Credit - Account No. 323
Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-107, interest expense on the balance in Deferral Account No. 179-107. Simple interest will be computed monthly on the opening balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

UNION GAS LIMITED

Accounting Entries for
Unabsorbed Demand Cost (UDC) Variance Account
Deferral Account No. 179-108

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No. 179-108 Other Deferred Charges – Unabsorbed Demand Cost Variance Account
Credit	-	Account No. 623 Cost of Gas

To record, as a debit (credit) in Deferral Account No. 179-108, the difference between the actual unabsorbed demand costs incurred by Union and the amount of unabsorbed demand charges included in rates as approved by the Board.

Debit	-	Account No. 179-108 Other Deferred Charges – Unabsorbed Demand Cost Variance Account
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-108, interest expense on the balance in Deferral Account No. 179-108. Simple interest will be computed monthly on the opening balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

UNION GAS LIMITED

Accounting Entries for
Inventory Revaluation Account
Deferral Account No. 179-109

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A, prescribed under the Ontario Energy Board Act.

Debit	-	Account No. 179-109 Other Deferred Charges – Inventory Revaluation
Credit	-	Account No. 152 Gas Stored Underground - Available for Sales
Credit	-	Account No. 153 Transmission Line Pack Gas

To record, as a debit (credit) in Deferral Account No. 179-109, the decrease (increase) in the value of gas inventory available for sale to sales service customers due to changes in Union's weighted average cost of gas approved by the Board for rate making purposes.

Debit	-	Account No. 179-109 Other Deferred Charges – Inventory Revaluation Account
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-109, interest expense on the balance in Deferral Account No. 179-109. Simple interest will be computed monthly on the opening balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

UNION GAS LIMITED

Accounting Entries for
Demand Side Management Variance Account
Deferral Account No. 179-111

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No.179-111 Demand Side Management Variance Account
Credit	-	Account No. 728 General Expense

To record as a debit (credit) in Deferral Account No. 179-111, the difference between actual and the approved direct DSM expenditure budget currently approved for recovery in rates, provided that any excess over the approved direct DSM expenditure budget does not exceed 15% of the direct DSM expenditure budget. Any excess over the approved direct DSM expenditure budget for the year must be for incremental DSM volume savings that are cost effective as determined by the Total Resource Cost Test.

Debit	-	Account No.179-111 Other Deferred Charges – Demand Side Management Variance Account
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-111, interest expense on the balance in Deferral Account No. 179-111. Simple interest will be computed monthly upon finalization of the year end balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

UNION GAS LIMITED

Accounting Entries for
Gas Distribution Access Rule (GDAR) Costs
Deferral Account No. 179-112

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No. 179-112 Other Deferred Charges - Deferred Gas Distribution Access Rule (GDAR) Costs
Credit	-	Account No. 728 General Expense

To record, as a debit (credit) in Deferral Account No. 179-112 the difference between the actual costs required to implement the appropriate process and system changes to achieve compliance with GDAR and the costs included in rates as approved by the Board.

Debit	-	Account No.179-112 Other Deferred Charges - Deferred Gas Distribution Access Rule (GDAR) Costs
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-112, interest on the balance in Deferral Account No. 179-112. Simple interest will be computed monthly on the opening balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

UNION GAS LIMITED

Accounting Entries for
Late Payment Penalty Litigation
Deferral Account No. 179-113

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No. 179-113 Late Payment Penalty Litigation Costs
Credit	-	Account No. 728 General Expense

To record, as a debit (credit) in Deferral Account No. 179-113, the costs Union incurs in connection with the late payment penalty litigation, including the Company's legal costs, cost of actuarial advice, costs of analyzing historic billing records and the cost of any judgment against the Company.

Debit	-	Account No. 179-113 Late Payment Penalty Litigation Costs
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-113, interest expense on the balance in Deferral Account No. 179-113. Simple interest will be computed monthly on the opening balance in the said account at the short-term interest rate as approved by the Board.

UNION GAS LIMITED

Accounting Entries for
Shared Savings Mechanism
Deferral Account No. 179-115

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No.179 -115 Shared Savings Mechanism
Credit	-	Account No. 579 Miscellaneous Operating Revenue

To record, as a debit in Deferral Account No. 179-115, the shareholder incentive earned by the Company in relation to its Demand Side Management (DSM) Programs.

Debit	-	Account No.179- 115 Other Deferred Charges – Shared Savings Mechanism
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit in Deferral Account No. 179 -115, interest expense on the balance in Deferral Account No. 179-115. Simple interest will be computed monthly upon finalization of the year end balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

UNION GAS LIMITED

Accounting Entries for
Carbon Dioxide Offset Credits
Deferral Account No. 179-117

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No.179 -117 Carbon Dioxide Offset Credits
Credit	-	Account No. 579 Miscellaneous Operating Revenue

To record, as a debit in Deferral Account No. 179-117, the amounts representing proceeds from the sale of or other dealings in carbon dioxide offset credits earned as a result of Union's DSM activity.

Debit	-	Account No.179 -117 Other Deferred Charges – Carbon Dioxide Offset Credits
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit in Deferral Account No. 179 -117, interest expense on the balance in Deferral Account No. 179-117. Simple interest will be computed monthly upon finalization of the year end balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

UNION GAS LIMITED

Accounting Entries for
Average Use Per Customer
Deferral Account No. 179-118

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No. 500 Sales Revenue
Credit	-	Account No. 179-118 Other Deferred Charges - Declining Average Use

To record as a debit (credit) in Deferral Account No. 179-118 the margin variance resulting from the difference between the actual rate of decline in use-per-customer and forecast rate of decline in use-per-customer included in gas delivery rates as approved by the Board in each year of the incentive regulation plan, 2008 through 2012. Actual and forecast rate of declines in use-per-customer will be calculated on a percentage and rate class specific basis for rate classes M1, M2, 01 and 10, be normalized for weather and exclude the impacts attributed to DSM which are captured in the Lost Revenue Adjustment Mechanism Deferral Account No. 179-75.

Debit	-	Account No. 179-118 Other Deferred Charges - Declining Average Use
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-118, interest on the balance in Deferral Account No. 179-118. Simple interest will be computed monthly on the opening balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

UNION GAS LIMITED

Accounting Entries for
CGAAP to IFRS Conversion Costs
Deferral Account No. 179-120

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No. 179-120 Other Deferred Charges - CGAAP to IFRS Conversion Costs
Credit	-	Account No. 728 General Expense

To record, as a debit (credit) in Deferral Account No. 179-120 the difference between the actual incremental one-time administrative costs incurred to convert accounting policies and processes from their current compliance with Canadian Generally Accepted Accounting Principles (CGAAP) to their future compliance with International Financial Reporting Standards (IFRS) and the costs included in rates as approved by the Board.

Debit	-	Account No.179-120 Other Deferred Charges - CGAAP to IFRS Conversion Costs
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-120, interest on the balance in Deferral Account No. 179-120. Simple interest will be computed monthly on the opening balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

UNION GAS LIMITED

Accounting Entries for
Cumulative Under-recovery – St. Clair Transmission Line
Deferral Account No. 179-121

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No. 105 Accumulated Depreciation – Utility Plant
Credit	-	Account No. 179-121 Cumulative Under-recovery – St. Clair Transmission Line

To record, as a credit in Deferral Account No. 179-121, the cost of removal for the St. Clair Transmission Line ordered by the Board in EB-2008-0411 to be equal to the amount of cumulative under-recovery of Union's St. Clair Pipeline, from 2003 until the time of the sale of the asset, to be refunded to ratepayers.

Debit	-	Account No. 171 Extraordinary Plant Losses
Credit	-	Account No. 105 Accumulated Depreciation – Utility Plant

To record, as a debit to Account No. 171, the loss on the sale of the St. Clair Transmission Line and related assets. The loss represents the cost of disposition ordered by the Board in EB-2008-0411 that could not have been provided for previously in the accumulated provision for depreciation.

Debit	-	Account No. 333 Other Income Deductions
Credit	-	Account No. 171 Extraordinary Plant Losses

To record, as a debit to Account No. 333, the write-off to operations for the loss on the sale of the St. Clair Transmission Line and related assets.

Debit	-	Account No. 323 Other Interest Expense
Credit	-	Account No. 179-121 Cumulative Under-recovery – St. Clair Transmission Line

To record, as a debit (credit) in Deferral Account No. 179-121, interest on the balance in Deferral Account No. 179-121. Simple interest will be computed monthly on the opening balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

UNION GAS LIMITED

Accounting Entries for
Impact of Removing St. Clair Transmission Line from Rates
Deferral Account No. 179-122

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No. 300 Operating Revenues
Credit	-	Account No. 179-122 Other Deferred Charges – St. Clair Transmission Line

To record, as a credit in Deferral Account No. 179-122, the impact of removing the St. Clair Transmission Line (and related St. Clair River Crossing) from rates (including all rate base and OM&A consequences) effective March 1, 2010 through December 31, 2010 as ordered by the Board in EB-2008-0411.

Debit	-	Account No. 323 Other Interest Expense
Credit	-	Account No. 179-122 Other Deferred Charges – St. Clair Transmission Line

To record, as a credit in Deferral Account No. 179-122, interest on the balance in Deferral Account No. 179-122. Simple interest will be computed monthly on the opening balance in the said account in accordance with the methodology approved by the Board in EB-2006-0117.

UNION GAS LIMITED

Accounting Entries for
Conservation Demand Management
Deferral Account No. 179-123

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No. 312 Non-Gas Operating Revenue
Credit	-	Account No.179-123 Other Deferred Charges – Conservation Demand Management

To record, as a credit in Deferral Account No. 179-123, 50% of the actual revenues generated from the Conservation Demand Management (CDM) program that will be paid to customers upon approval by the Board for rate making purposes.

Debit	-	Account No.179-123 Other Deferred Charges – Conservation Demand Management
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-123, interest expense on the balance in Deferral Account No. 179-123. Simple interest will be computed monthly on the opening balance in the said account at the short term debt rate as approved by the Board in EB-2006-0117.

UNION GAS LIMITED

Accounting Entries for
Harmonized Sales Tax
Deferral Account No. 179-124

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No. 300 Operating revenue
Credit	-	Account No.179-124 Other Deferred Charges – Harmonized Sales Tax

To record, as a credit in Deferral Account No. 179-124, the amount of Provincial Sales Tax (PST) previously paid and collected in approved rates now subject to Harmonized Sales Tax (HST) tax credits. Also, to record as a debit in Deferral Account No. 179-124, the amount of HST paid on taxable items for which no tax credits are received from the Canadian Revenue Agency (CRA).

Debit	-	Account No. 323 Other Interest Expense
Credit	-	Account No.179 -124 Other Deferred Charges – Harmonized Sales Tax

To record, as a credit (debit) in Deferral Account No. 179-124, interest expense on the balance in Deferral Account No. 179-124. Simple interest will be computed monthly on the opening balance in the said account at the short term debt rate as approved by the Board in EB-2006-0117.

UNION GAS LIMITED

Accounting Entries for
Demand Side Management Incentive
Deferral Account No. 179-126

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No. 179-126 Other Deferred Charges – Demand Side Management Incentive
Credit	-	Account No. 319 Other Income

To record, as a debit in Deferral Account No. 179-126, the shareholder incentive earned by the Company in relation to its Demand Side Management (DSM) Programs.

Debit	-	Account No.179-126 Other Deferred Charges – Demand Side Management Incentive
Credit	-	Account No. 323 Other Interest Expense

To record, as a debit (credit) in Deferral Account No. 179-126, interest on the balance in Deferral Account No. 179-126. Simple interest will be computed monthly on the opening balance in the said account at the short term debt rate as approved by the Board in EB-2006-0117.

UNION GAS LIMITED

Accounting Entries for
Pension Charge on Transition to US GAAP
Deferral Account No. 179-127

Account numbers are from the Uniform System of Accounts for Gas Utilities, Class A prescribed under the Ontario Energy Board Act.

Debit	-	Account No. 179-127 Other Deferred Charges – Pension Charge on Transition to US GAAP
Credit	-	Account No. 212 Retained Earnings

To record, as a debit in Deferral Account No. 179-127, the amount recognized in retained earnings associated with transitioning accounting standards and reporting to US Generally Accepted Accounting Principles (GAAP) for previously unrecorded pension expenses.

UNION GAS LIMITED

NON-COMPLIANCE WITH UNIFORM SYSTEM OF ACCOUNTS

Union is in compliance with the Uniform System of Accounts with the following exceptions:

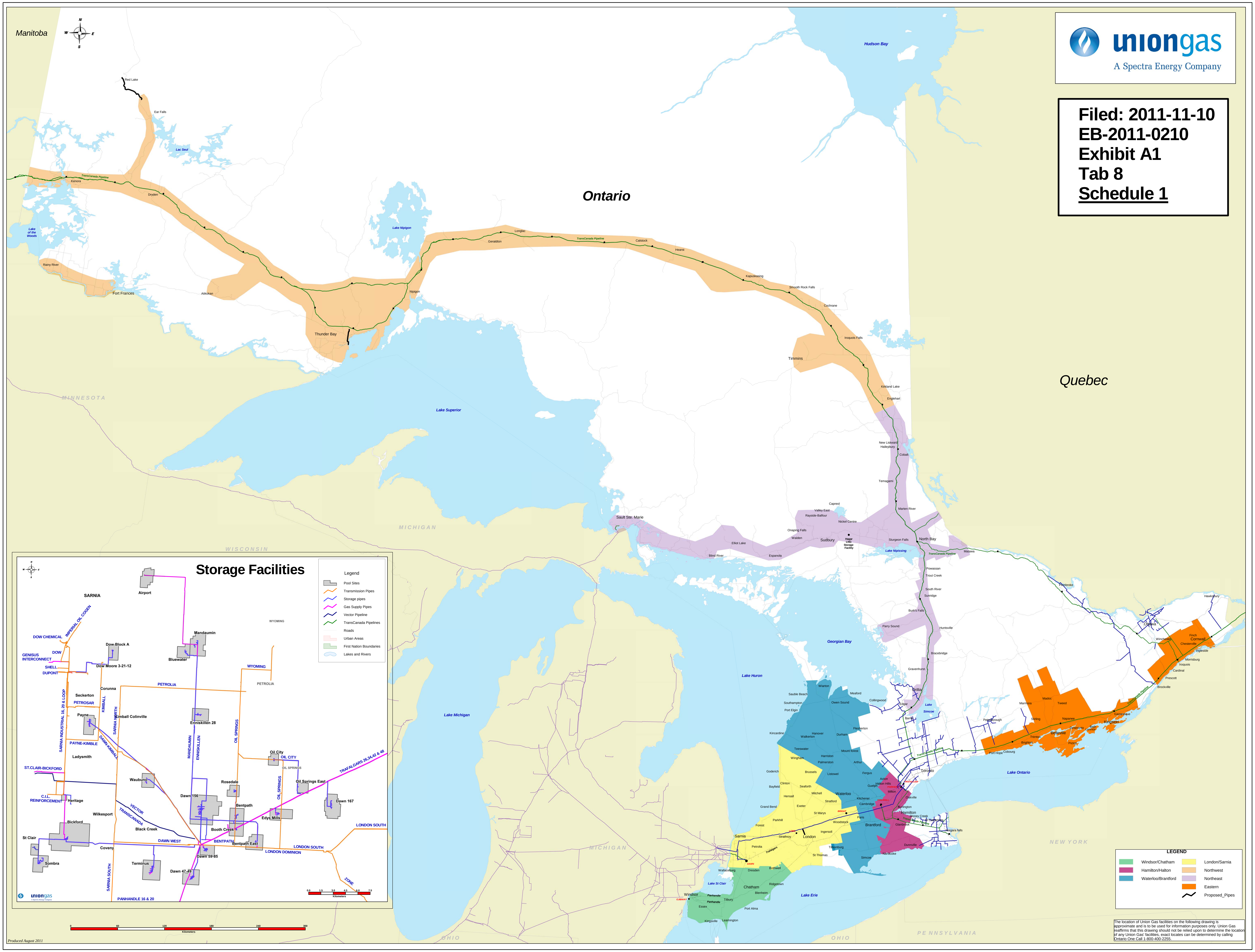
OPERATING & MAINTENANCE EXPENSE ACCOUNTS

Union is unable to separate all of its Operating and Maintenance Expense Accounts into the Detailed Accounts included in the Uniform System of Accounts. Union reports its operating and maintenance expense items by General Accounts only.

COST OF GAS INVENTORY

For Account No. 152 "Gas in Storage – Available for Sale", the Uniform System of Accounts requires that "Gas included in this account be valued at cost on a consistent basis". Union records gas inventory at the gas inventory reference price approved by the Board. The difference between actual costs and the reference price is recorded in the appropriate deferral accounts as approved by the Board in the RP-2003-0063 proceeding.

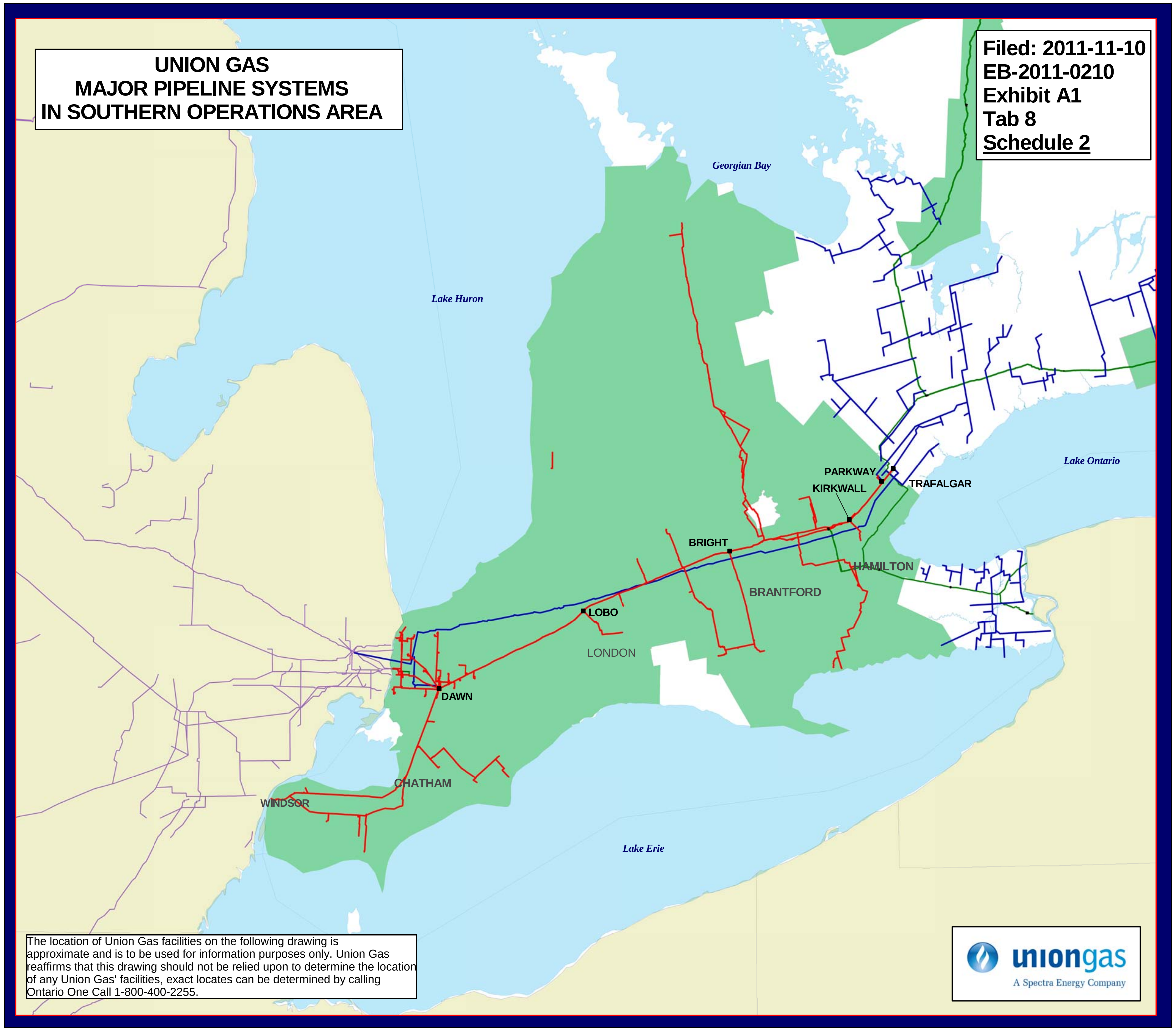
Filed: 2011-11-10
EB-2011-0210
Exhibit A1
Tab 8
Schedule 1



The location of Union Gas facilities on the following drawing is approximate and is to be used for information purposes only. Union Gas reaffirms that this drawing should not be relied upon to determine the location of any Union Gas' facilities, exact locates can be determined by calling Ontario One Call 1-800-400-2255.

UNION GAS
MAJOR PIPELINE SYSTEMS
IN SOUTHERN OPERATIONS AREA

Filed: 2011-11-10
EB-2011-0210
Exhibit A1
Tab 8
Schedule 2



The location of Union Gas facilities on the following drawing is approximate and is to be used for information purposes only. Union Gas reaffirms that this drawing should not be relied upon to determine the location of any Union Gas' facilities, exact locates can be determined by calling Ontario One Call 1-800-400-2255.

LIST OF AFFILIATE TRANSACTIONS

Attached are Union's Affiliate Transactions for the years 2010 and 2011 actuals. The attached reflects the dollar amounts and the basis on which the amounts were determined for Union's shared services, subsidiaries and related party transactions during this time period. Union does not anticipate the scope or magnitude of its Affiliate Transactions as shown on the attached will vary significantly in 2012 and 2013.

UNION GAS LIMITED
Affiliate Transactions

Line No.		2010 (a) ($)	2011 * (b) ($)	
	A. REVENUES			
	1. S&T Revenue			
1	Market Hub Partners L.P.	192,654	218,193	/u
2	Sarnia Airport Pool L.P.	945,404	941,144	/u
3	Huron Tipperary Limited Partnership	118,506	116,116	/u
4	Total	1,256,564	1,275,453	/u

(Note: All above services provided according to Union's Board approved rate schedules.)

Line No.		2010 (a) ($)	2011 * (b) ($)	
	2. Dividend on Common Shares Paid to Great Lakes Basin Energy L.P. [(1)]			
5	March 31, 2010; March 25, 2011	16,190,000	16,190,000	
6	June 30, 2010; June 30, 2011	16,190,000	16,190,000	/u
7	September 30, 2010; September 30, 2011	16,190,000	16,190,000	/u
8	December 29, 2010; December 28, 2011	141,190,000	96,190,000	/u
9	Total	189,760,000	144,760,000	/u
	3. Service Agreements (See Mr. Dave Hockin's evidence at Exhibit D1, Tab 8 for further detail)			
10	Outbound	10,182,203	11,697,201	/u

4. Intercompany Loan-Westcoast Energy Inc. [(2)]

Line No.		2010 Month-End Balance (a) ($ millions)	2010 Income (b) ($)	2010 Expenses (c) ($)	2011 Month-End Balance (d) ($ millions)	2011 Income (e) ($)	2011 Expenses (f) ($)	
11	January	0.00	640	0	(212.00)	0	186,663	
12	February	0.00	1,312	0	(158.00)	0	153,726	
13	March	0.00	4,647	0	(100.00)	0	132,919	
14	April	0.00	5,907	0	(58.00)	0	54,048	
15	May	10.00	2,312	0	(39.00)	0	14,469	
16	June	0.00	0	219	(12.00)	0	4,080	
17	July	7.00	0	26,633	0	4,469	0	
18	August	0.00	3,036	0	(18.00)	9,429	0	
19	September	(8.00)	0	833	0	0	981	/u
20	October	(11.50)	0	2,230	(130.00)	0	12,537	/u
21	November	(40.00)	0	9,228	(101.00)	0	76,173	/u
22	December	(198.00)	0	80,817	(99.00)	0	45,340	/u
23	Total		17,854	119,960		13,898	680,936	/u

UNION GAS LIMITED
Affiliate Transactions

Line No.		2010	2011 *	
		(a)	(b)	
		($)	($)	
	B. COSTS			
	1. Gas and Storage Purchases			
24	St. Clair Pipelines L.P.	971,625	971,625	/u
25	Market Hub Partners	1,783,500	1,783,500	/u
26	Westcoast - Empress	3,739,035	49,143,553	/u
27	Sarnia Airport Pool L.P.	4,830,614	4,525,785	/u
28	Huron Tipperary Limited Partnership	643,740	586,927	/u
29	Total	11,968,514	57,011,390	/u
	(Note: Gas purchases made using Union's tendering procedure in effect for all system gas purchases and as filed with the Board.)			
	2. Upstream Transportation (3)			
30	St. Clair Pipelines LP (Bluewater Pipeline)	629,628	629,628	/u
31	St. Clair Pipelines LP (St. Clair River Crossing)	342,000	342,000	/u
32	Total	971,628	971,628	/u
	(Note: Service purchased by Union as per NEB approved toll schedule.)			
	3. Service Agreements (See Dave Hockin's evidence at Exhibit D1, Tab 8 for further detail)			
33	Inbound	9,462,153	8,956,118	/u

Note:

(1) Great Lakes Basin Energy L.P. is a wholly-owned subidiary of Westcoast Energy Inc.

(2) Intercompany loans are reported as the balance outstanding as of the last day of the calendar month. A negative number indicates Union is the borrower, and a positive number indicates Union is the lender. Interest income and interest expense is earned based on the daily balance throughout the month. Where the charts shows interest income or expense and a zero loan balance at the end of the month, this indicates there was a balance outstanding during the month but not on the last day of the month. The interest rate on these loans is calculated based on the monthly average of 30-day Bankers Acceptance Rates.

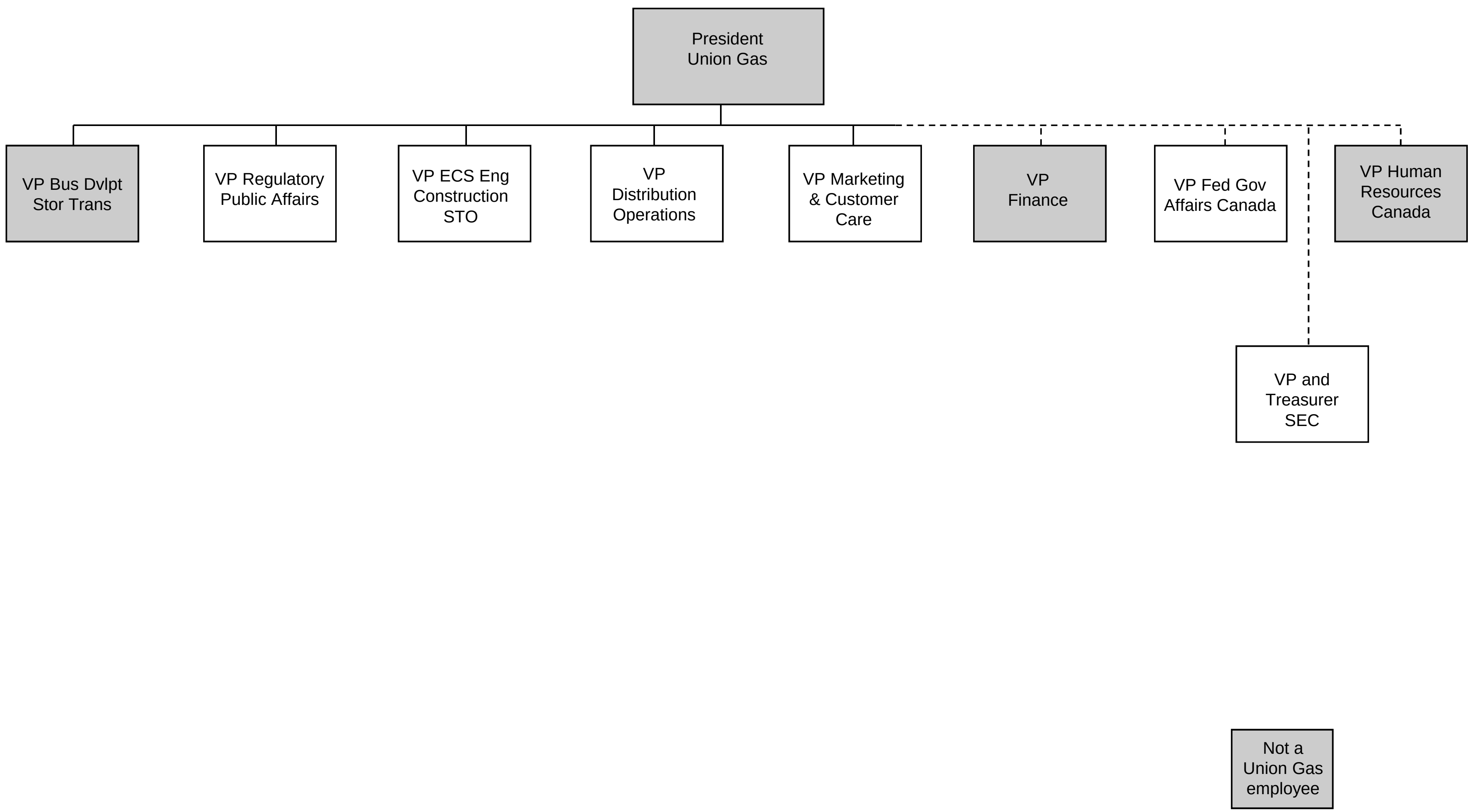
(3) Contracts are ongoing. The Bluewater Pipeline charges under the Second Amendment to the Transportation Services Agreement between St. Clair Pipelines (1996) Ltd. and Union Gas Limited dated November 1, 1995. The charges for the St. Clair River Crossing under Terms of Agreement between St. Clair Pipelines Limited and Union Gas Limited dated May 1, 1988.

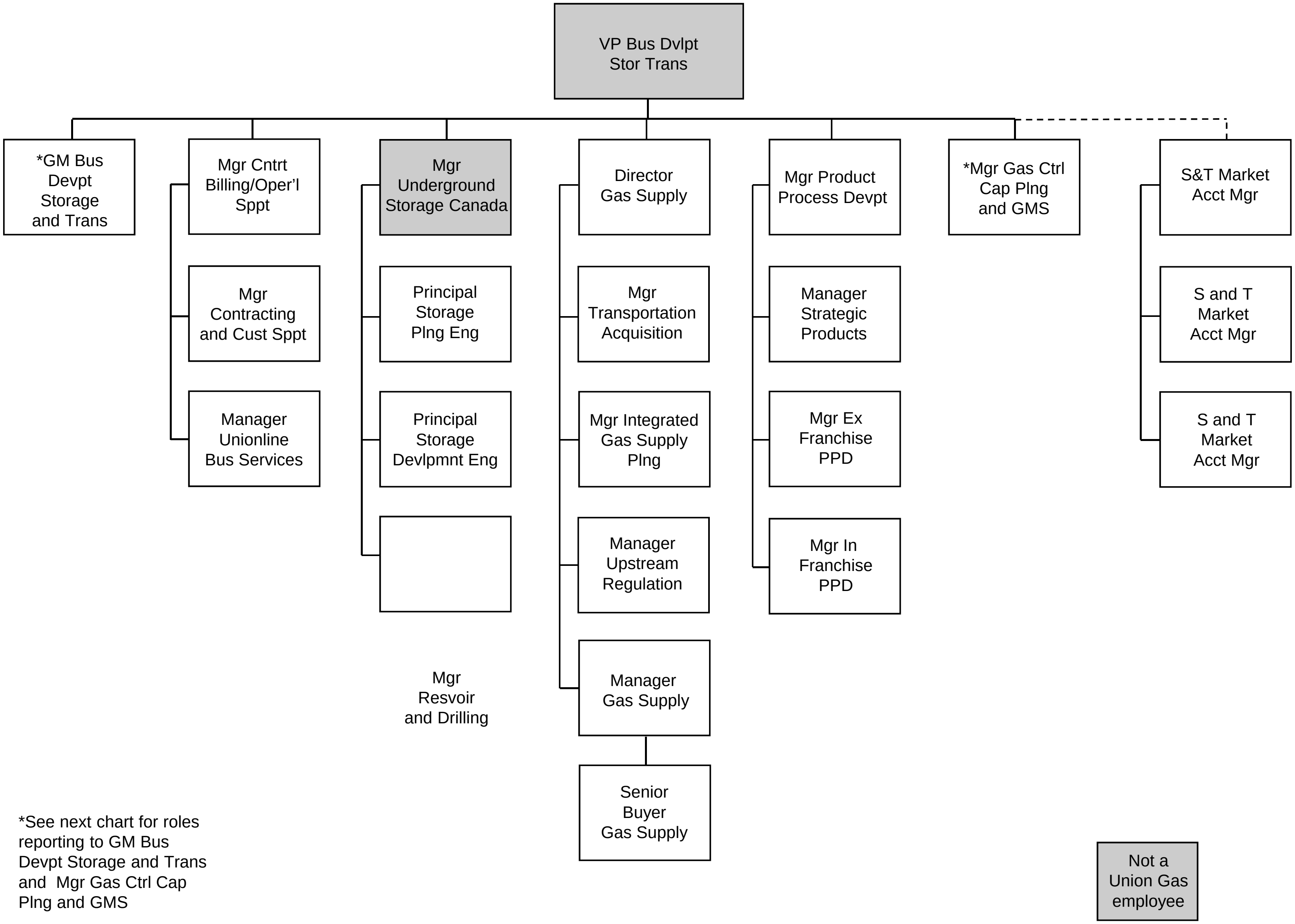
***** Includes Dec 31 year-to-date information. /u

UNION GAS LIMITED

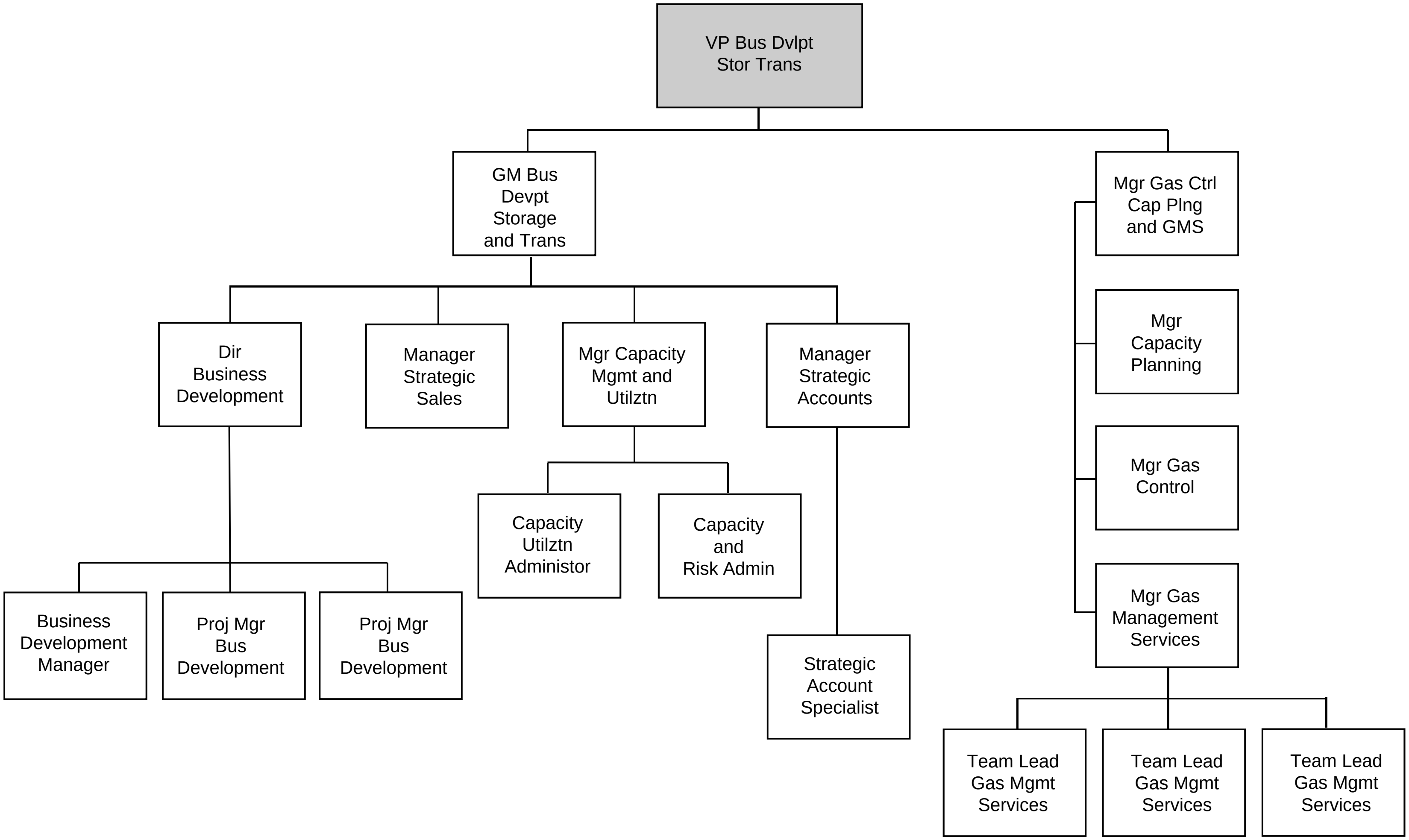
UTILITY ORGANIZATION CHARTS

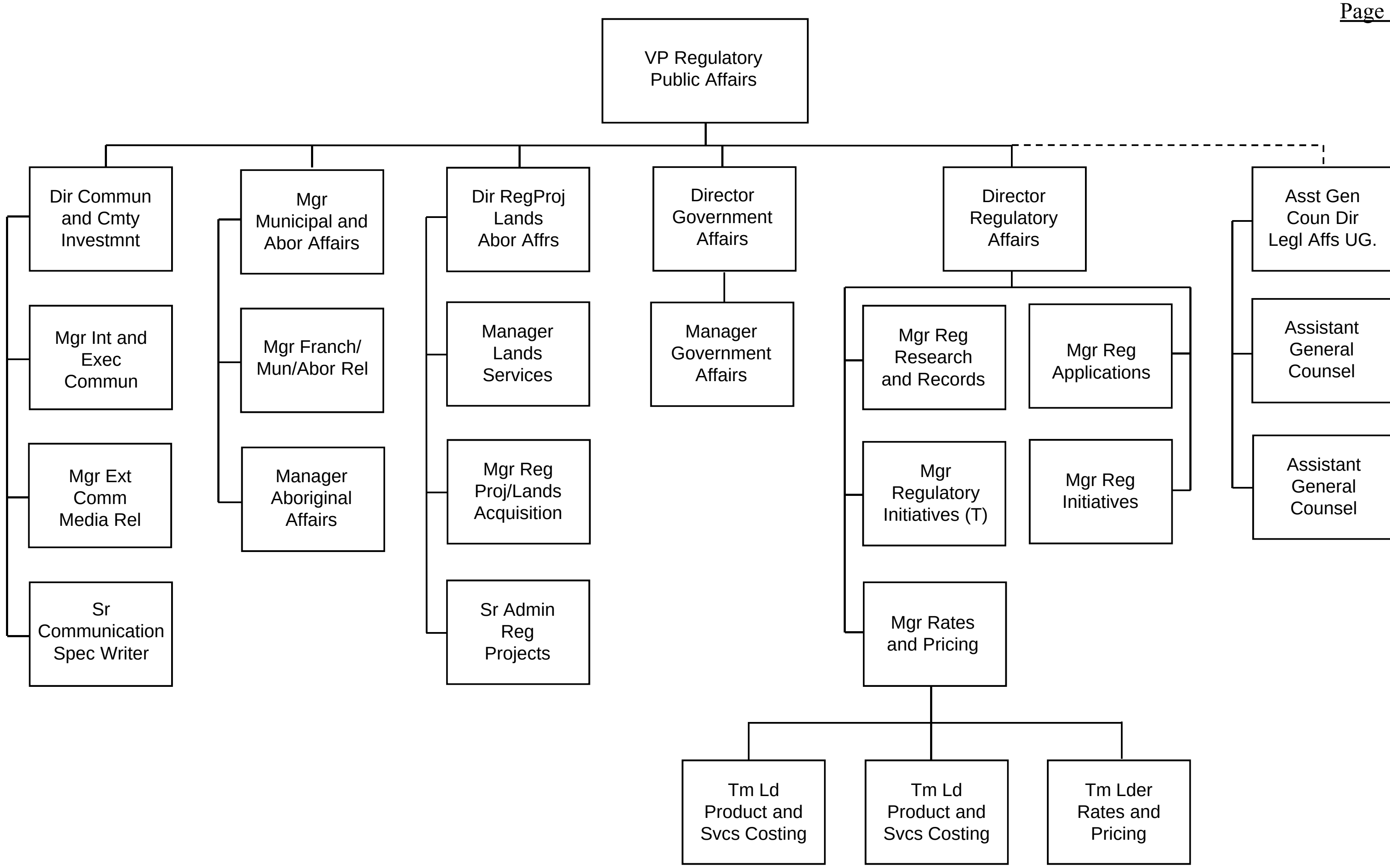
Attached are Union Gas's Utility Organization Charts. The charts show the reporting relationships of management level employees. The solid line reporting relationships shown on the chart represent direct reporting relationships. Dotted line reporting relationships occur when a service activity is managed by an affiliate. These instances create a dual reporting relationship to both Union's Executive and Westcoast Energy Inc. shared services management.

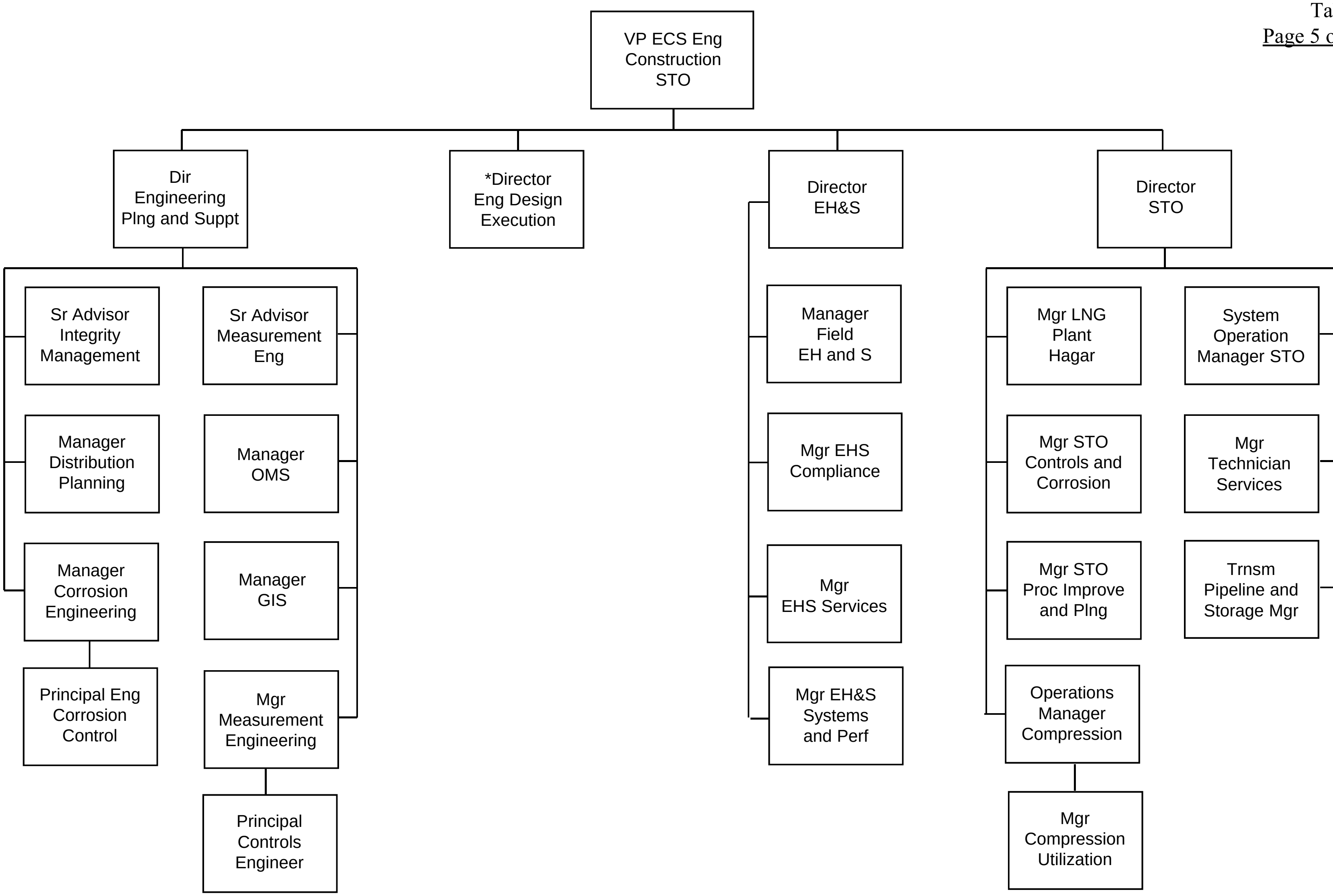

President
Union Gas
VP Bus Dvlpt
Stor Trans
VP Regulatory
Public Affairs
VP ECS Eng
Construction
STO
VP
Distribution
Operations
VP Marketing
& Customer
Care
VP
Finance
VP Fed Gov
Affairs Canada
VP Human
Resources
Canada
VP and
Treasurer
SEC
Not a
Union Gas
employee



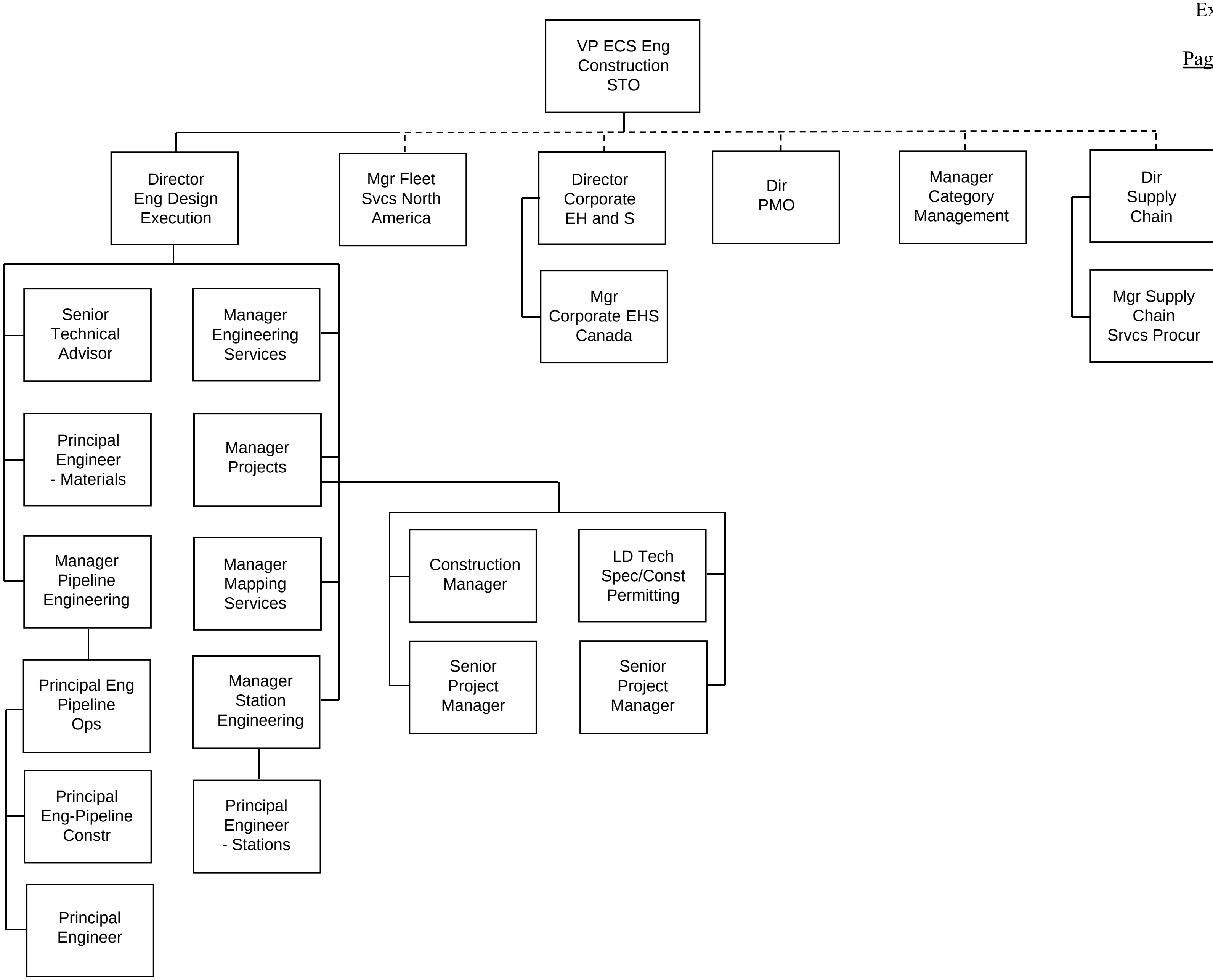
*See next chart for roles reporting to GM Bus Devpt Storage and Trans and Mgr Gas Ctrl Cap Plng and GMS

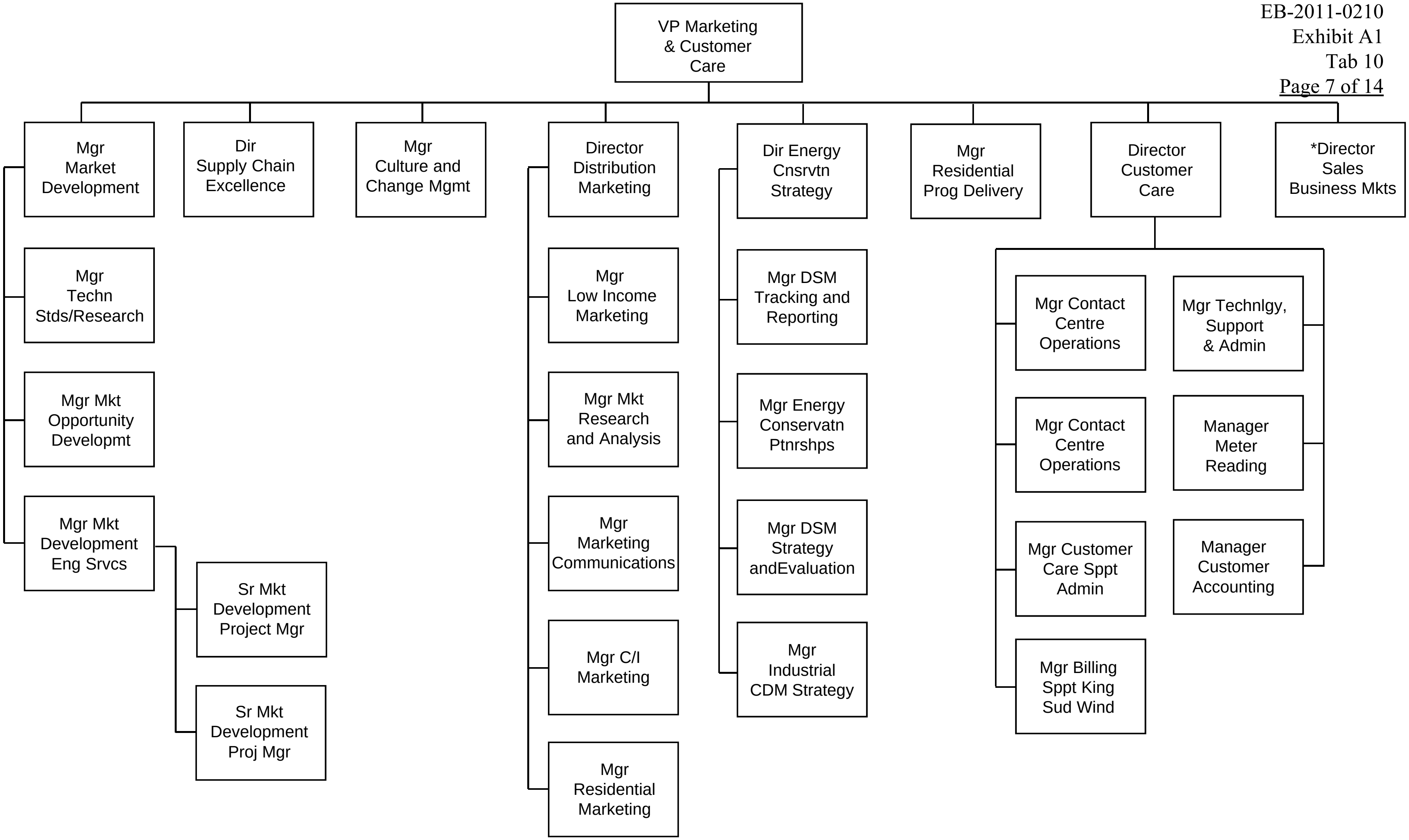

VP Bus Dvlpt Stor Trans
GM Bus Devpt Storage and Trans
Mgr Gas Ctrl Cap Plng and GMS
Dir Business Development
Manager Strategic Sales
Mgr Capacity Mgmt and Utilztn
Manager Strategic Accounts
Mgr Capacity Planning
Mgr Gas Control
Capacity Utilztn Administor
Capacity and Risk Admin
Mgr Gas Management Services
Business Development Manager
Proj Mgr Bus Development
Proj Mgr Bus Development
Strategic Account Specialist
Team Lead Gas Mgmt Services
Team Lead Gas Mgmt Services
Team Lead Gas Mgmt Services


VP Regulatory Public Affairs
Dir Commun and Cmty Investmnt
Mgr Int and Exec Commun
Mgr Ext Comm Media Rel
Sr Communication Spec Writer
Mgr Municipal and Abor Affairs
Mgr Franch/ Mun/Abor Rel
Manager Aboriginal Affairs
Dir RegProj Lands Abor Affrs
Manager Lands Services
Mgr Reg Proj/Lands Acquisition
Sr Admin Reg Projects
Director Government Affairs
Manager Government Affairs
Director Regulatory Affairs
Mgr Reg Research and Records
Mgr Reg Applications
Mgr Regulatory Initiatives (T)
Mgr Reg Initiatives
Mgr Rates and Pricing
Tm Ld Product and Svcs Costing
Tm Ld Product and Svcs Costing
Tm Lder Rates and Pricing
Asst Gen Coun Dir Legl Affs UG.
Assistant General Counsel
Assistant General Counsel

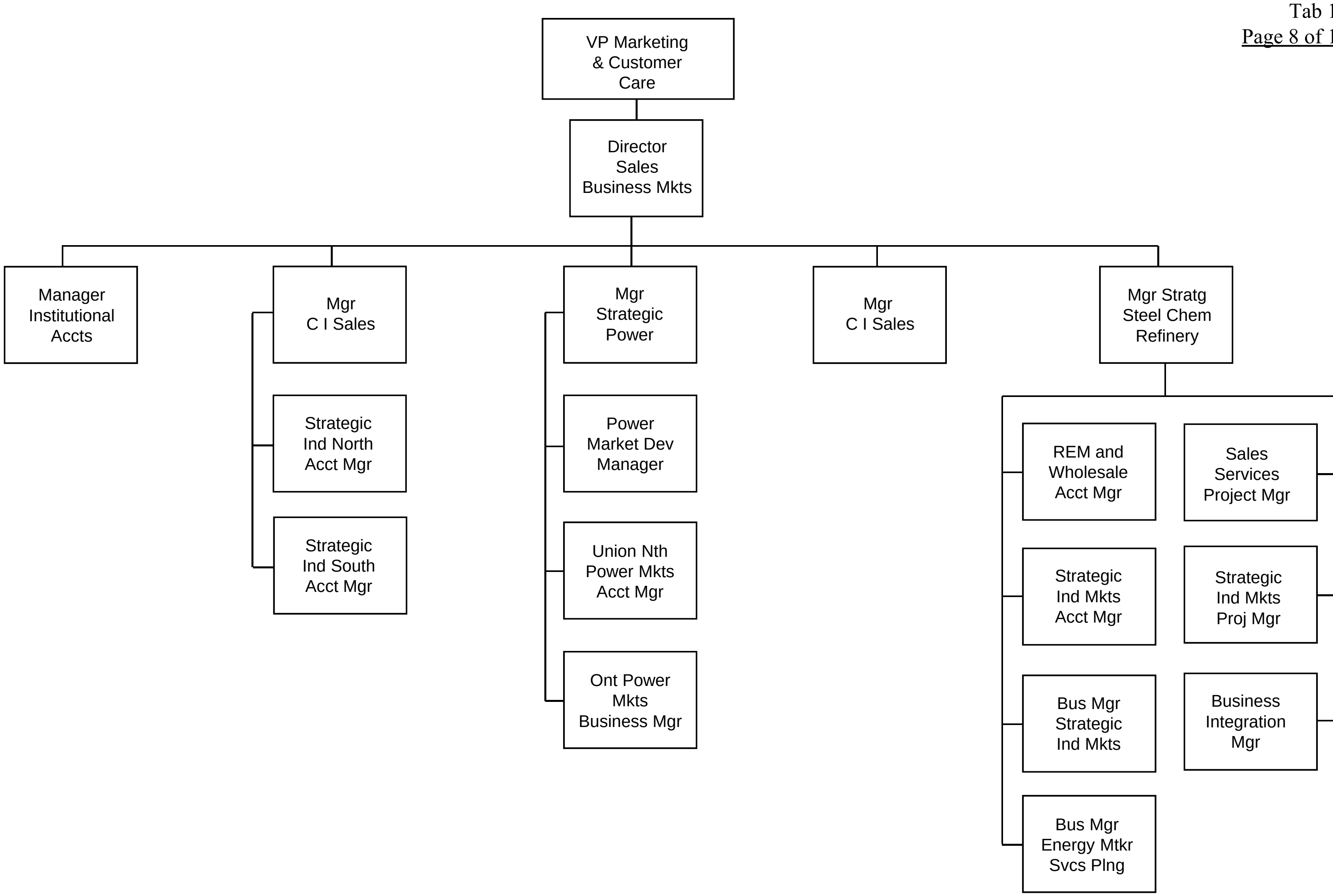


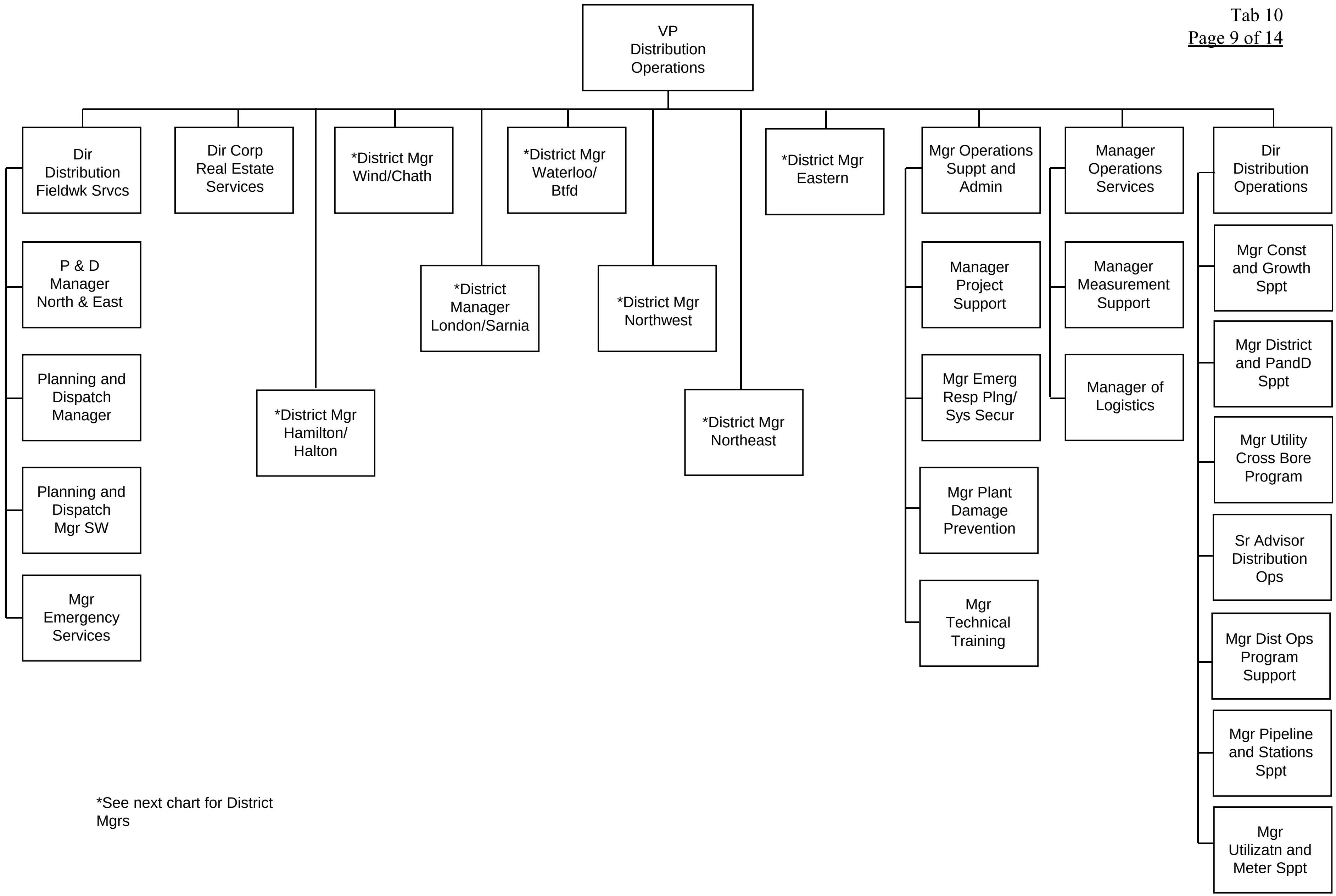
*See next chart for Director Eng Design Execution and dotted line reports


VP ECS Eng Construction STO
Director Eng Design Execution
Mgr Fleet Svcs North America
Director Corporate EH and S
Dir PMO
Manager Category Management
Dir Supply Chain
Mgr Corporate EHS Canada
Mgr Supply Chain Srvcs Procur
Senior Technical Advisor
Manager Engineering Services
Principal Engineer - Materials
Manager Projects
Manager Pipeline Engineering
Manager Mapping Services
Principal Eng Pipeline Ops
Manager Station Engineering
Principal Eng-Pipeline Constr
Principal Engineer - Stations
Principal Engineer
Construction Manager
LD Tech Spec/Const Permitting
Senior Project Manager
Senior Project Manager



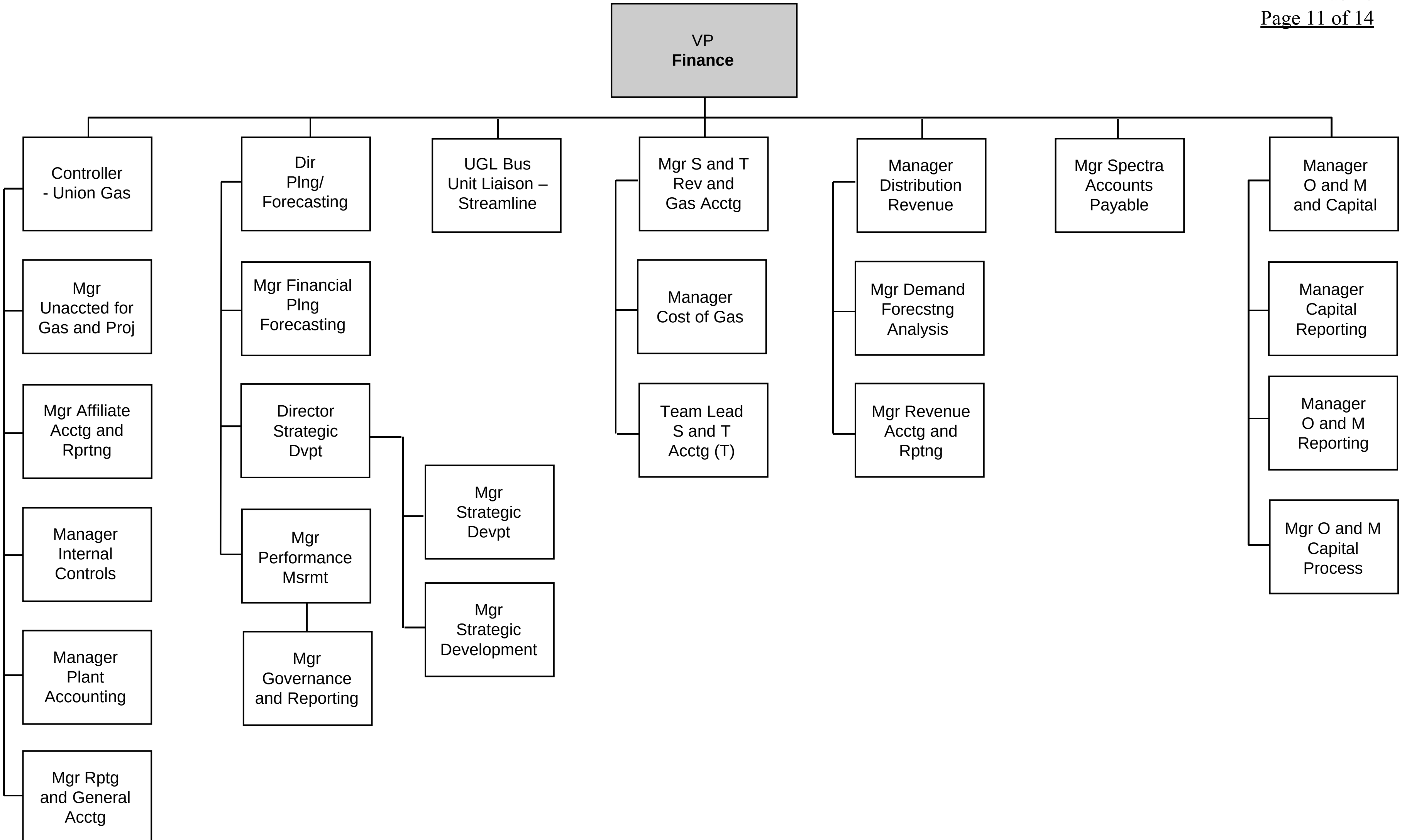
*See next chart for Director Sales Business Mkts


VP Marketing & Customer Care
Director Sales Business Mkts
Manager Institutional Accts
Mgr C I Sales
Strategic Ind North Acct Mgr
Strategic Ind South Acct Mgr
Mgr Strategic Power
Power Market Dev Manager
Union Nth Power Mkts Acct Mgr
Ont Power Mkts Business Mgr
Mgr C I Sales
Mgr Stratg Steel Chem Refinery
REM and Wholesale Acct Mgr
Sales Services Project Mgr
Strategic Ind Mkts Acct Mgr
Strategic Ind Mkts Proj Mgr
Bus Mgr Strategic Ind Mkts
Business Integration Mgr
Bus Mgr Energy Mtkr Svcs Plng



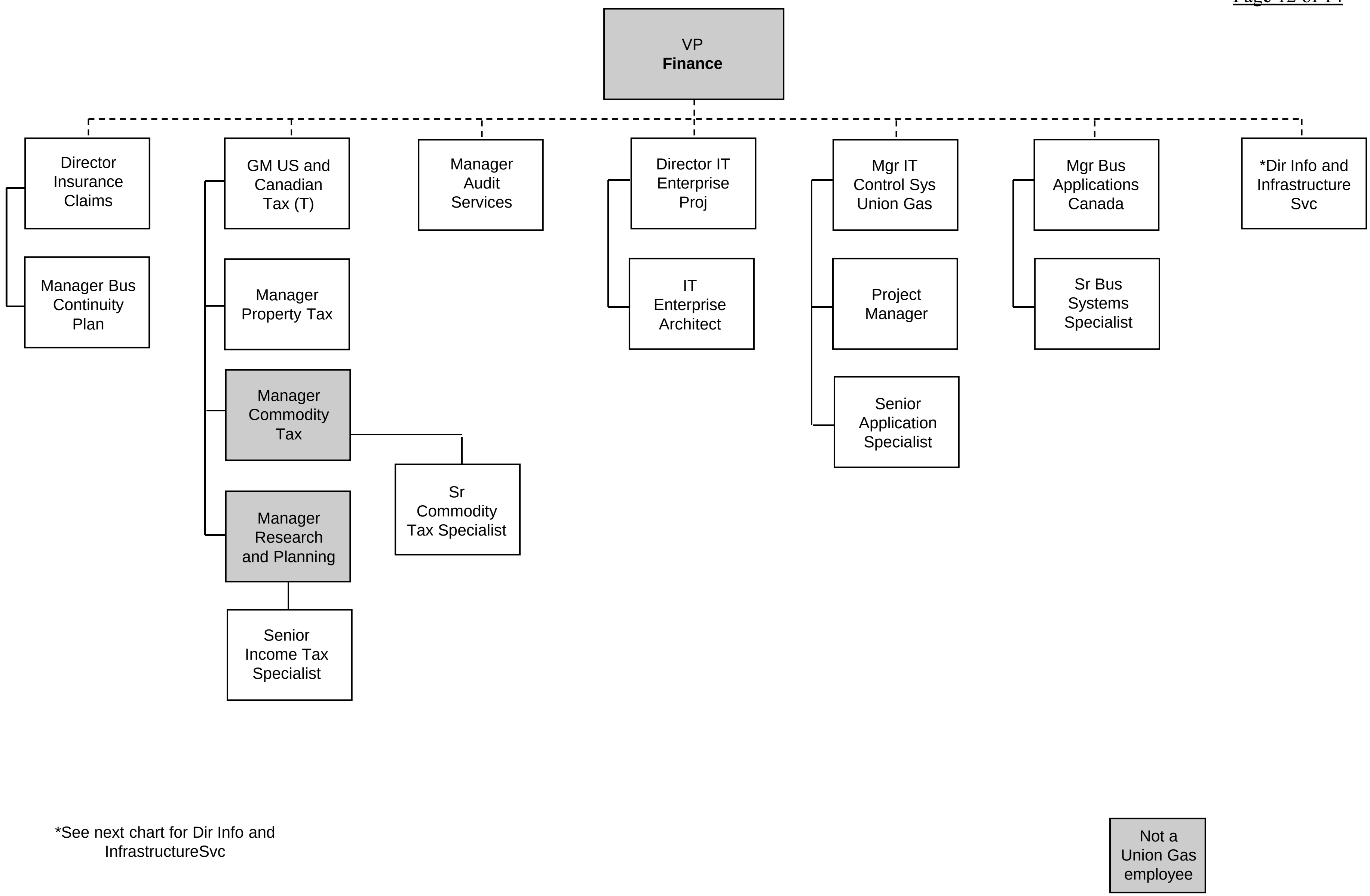
*See next chart for District Mgrs

- VP Distribution Operations
  - District Mgr Wind/Chat
    - Mgr Construction and Growth
    - Mgr District Support
  - District Manager London/Sarnia
    - Mgr of Construction and Growth
    - Mgr of District Support
  - District Mgr Waterloo/ Btfd
    - Mgr Construction and Growth
    - Mgr District Support
  - District Mgr Hamilton/ Halton
    - Mgr Construction and Growth
    - Mgr District Support
  - District Mgr Eastern
    - Mgr Construction and Growth
    - Manager District Support
    - Util Svc Construction Mgr Bell
    - Util Svc Constr Mgr Cobourg
    - Util Svc Construction Mgr Cnwl
    - Util Svc Construction Mgr King
  - District Mgr Northeast
    - Mgr Construction and Growth
    - District Support Manager
    - Utility Services & Constr Mgr
    - Utility Services Constr Mgr
  - District Mgr Northwest
    - Mgr Construction & Growth
    - Manager District Support
    - Util Svc and Const Mg Ft Fran
    - Utility Svc &Const Mgr Timmins

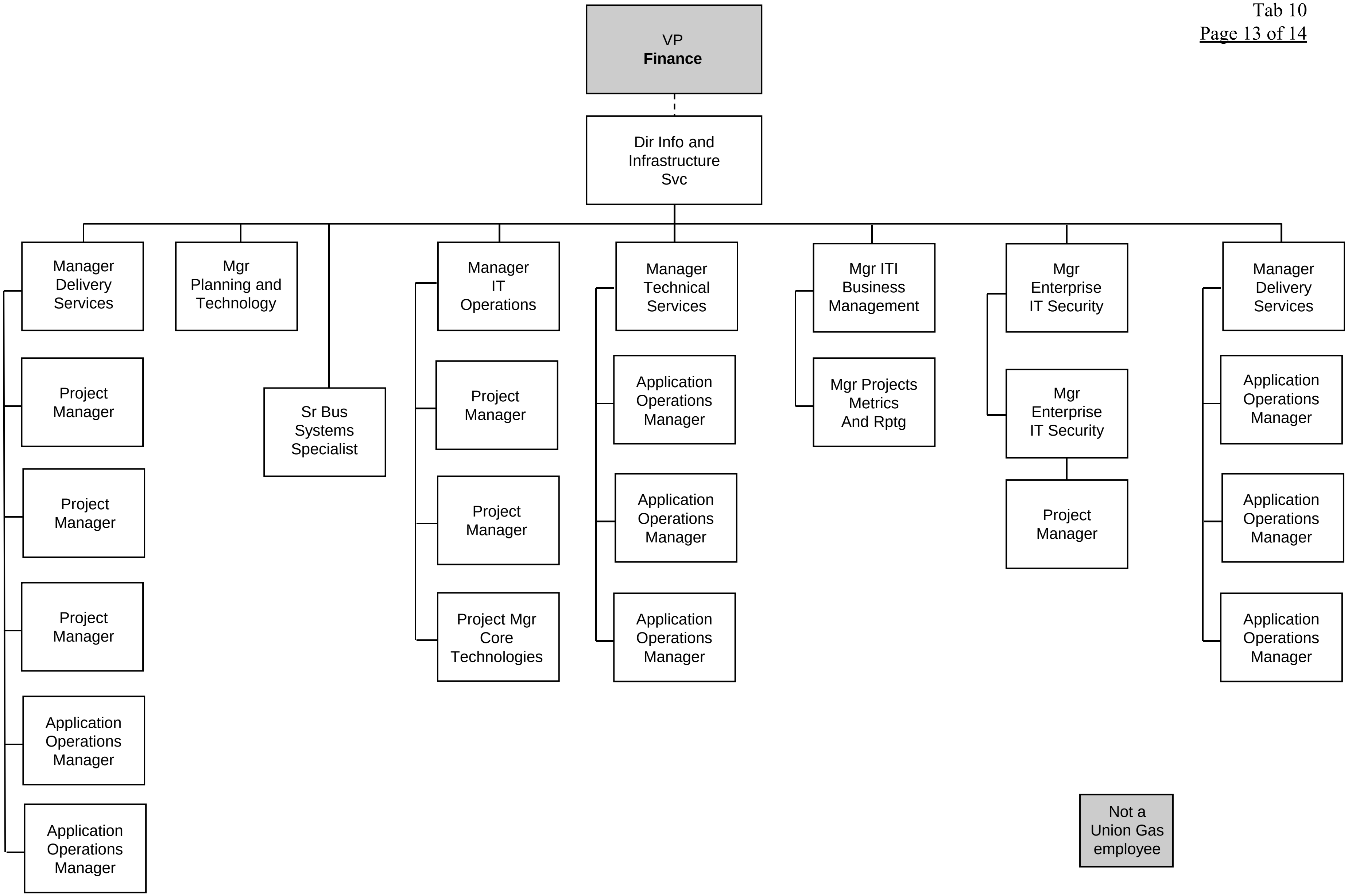


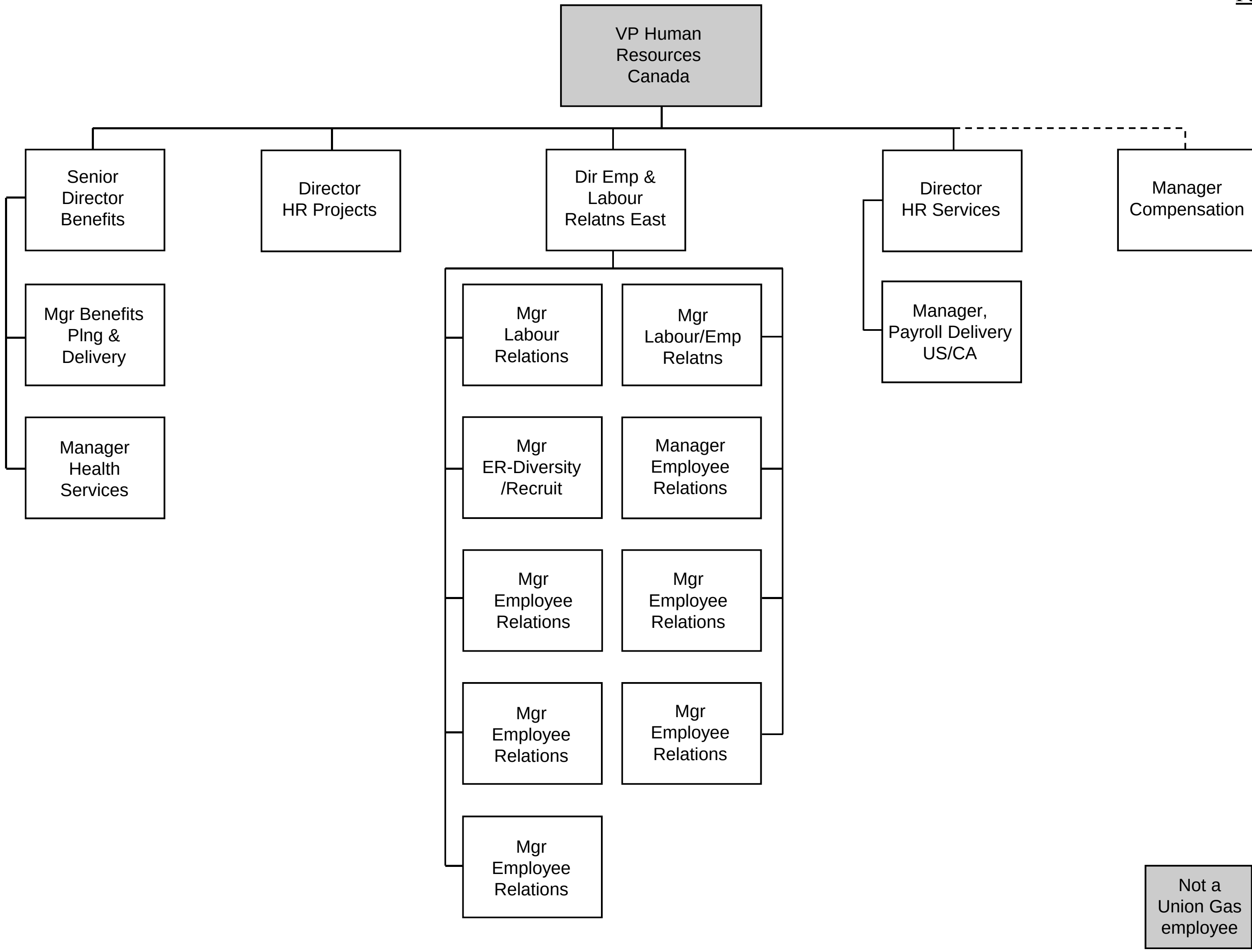
See next chart for dotted line reports

Not a Union Gas employee



*See next chart for Dir Info and InfrastructureSvc


VP
Finance
Dir Info and Infrastructure Svc
Manager Delivery Services
Project Manager
Project Manager
Project Manager
Application Operations Manager
Application Operations Manager
Mgr Planning and Technology
Sr Bus Systems Specialist
Manager IT Operations
Project Manager
Project Manager
Project Mgr Core Technologies
Manager Technical Services
Application Operations Manager
Application Operations Manager
Application Operations Manager
Mgr ITI Business Management
Mgr Projects Metrics And Rptg
Mgr Enterprise IT Security
Mgr Enterprise IT Security
Project Manager
Manager Delivery Services
Application Operations Manager
Application Operations Manager
Application Operations Manager
Not a Union Gas employee


VP Human Resources Canada
Senior Director Benefits
Director HR Projects
Dir Emp & Labour Relatns East
Director HR Services
Manager Compensation
Mgr Benefits Plng & Delivery
Manager Health Services
Mgr Labour Relations
Mgr Labour/Emp Relatns
Mgr ER-Diversity /Recruit
Manager Employee Relations
Mgr Employee Relations
Mgr Employee Relations
Mgr Employee Relations
Mgr Employee Relations
Mgr Employee Relations
Manager, Payroll Delivery US/CA
Not a Union Gas employee

WESTCOAST ENERGY INC.

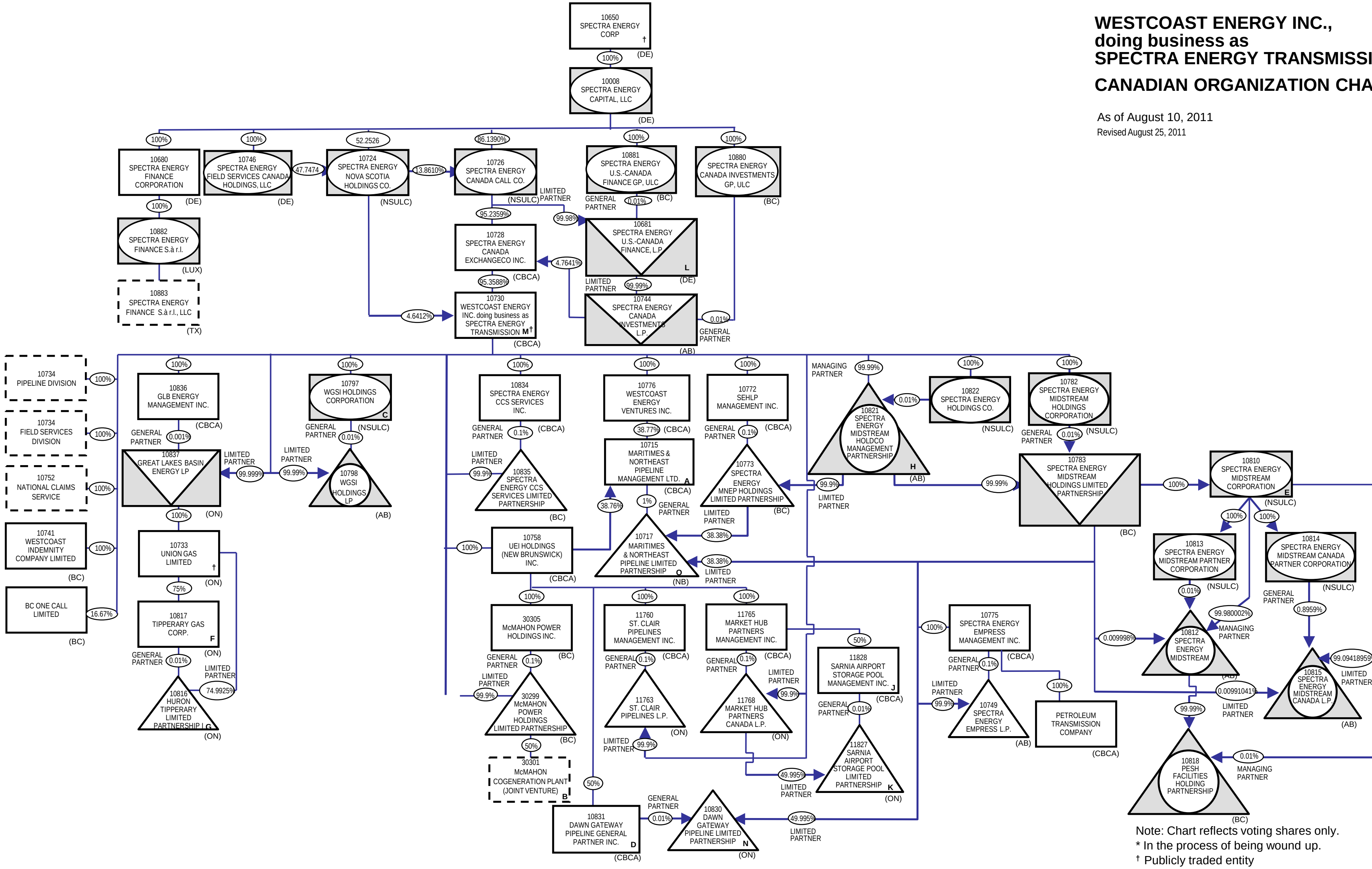
CORPORATE ORGANIZATION CHART

Attached is the Westcoast Energy Inc. doing business as Spectra Energy Transmission Organization Chart.

WESTCOAST ENERGY INC., doing business as SPECTRA ENERGY TRANSMISSION

CANADIAN ORGANIZATION CHART

As of August 10, 2011
Revised August 25, 2011



Note: Chart reflects voting shares only.
* In the process of being wound up.
† Publicly traded entity

LEGEND

A ExxonMobil Canada Hibernia Finance Ltd. owns 955 common shares (9.55%) and NSP Pipeline Management Limited owns 1,292 common shares (12.92%). UEI Holdings (New Brunswick) Inc. is the manager.
B Atco Power Canada Ltd. is the other 50% JV owner.
C Buckinghorse assets.
D Owned 50% by DTE Dawn Gateway Canada Inc.
E Assets: Jedney, Highway and 50% in Boundary Lake.
F Owned 25% by a 3rd party, Tribute Resources Inc.
G Owned 24.9975% by a 3rd party, Tribute Resources Inc.
H Westcoast Energy Inc. is the managing partner.
I
J 50% owned by AltaGas Holdings Inc.
K 49.995% owned by AltaGas Ltd.
L Spectra Energy Nova Scotia Holdings Co. owns .01% of Spectra Energy U.S.-Canada Finance LP.
M Spectra Energy Canada Investments LP holds 100% of Second Preferred, Series B Shares
N 49.995% owned by DTE Vector Canada Inc.
O ExxonMobil Canada Hibernia Finance Ltd. holds 9.45% and NSP Pipeline Incorporated holds 12.79%.

GENERAL PARTNERSHIP
DIVISION
HYBRID PARTNERSHIP FOR CDN TAX. CORPORATION FOR U.S. TAX
LIMITED PARTNERSHIP
HYBRID CORP FOR CDN TAX. DISREGARDED ENTITY FOR U.S. TAX
HYBRID PARTNERSHIP FOR CDN TAX. DISREGARDED ENTITY FOR U.S. TAX

unionGas

DIRECTORS AND OFFICERS
(Effective January 9, 2012)

DIRECTORS	
Stephen W. Baker (Chair)	
Bruce E. Pydee	
David G. Unruh	
OFFICERS	
President	Stephen W. Baker
Chief Financial Officer	J. Patrick Reddy
Vice President, Regulatory and Public Affairs	M. Richard Birmingham
Vice President and General Counsel	Bruce E. Pydee
Vice President, Human Resources	Bohdan I. Bodnar
Vice President, Government and Aboriginal Affairs	Menelaos Ydreos
Vice President, Business Development – Storage and Transmission	Mark Isherwood
Vice President, Engineering, Construction and Storage and Transmission Operations	Paul Rietdyk
Vice President, Distribution Operations	Mike Shannon
Vice President, Finance	Joe R. Martucci
Vice President and Treasurer	Guy G. Buckley
Vice President, Federal Government Affairs	Tim Kennedy
Assistant Treasurer	Paul K. Haralson
Corporate Secretary	Patricia M. Rice
Assistant Secretary	Leigh A. Hodgins
Assistant Secretary	Joe Marra

UNION GAS LIMITED

STATUS OF OUTSTANDING BOARD DIRECTIVES

The following summarizes the status of outstanding Board directives.

Board File No.	Directive	Response
EBLO 251 Bright to Owen Sound Dawn-Trafalgar Facilities Expansion Program	Union is directed to report in each rates case for the next 30 years, an update to the peak day volume forecast shown for 1996/1997 in Appendix A to its supplementary evidence.	B1, Tab 5
EBLO 253 Wingham Area Project	Union is directed to record separately the monies obtained from market contributions for this project for each class of customer and to report on this matter at future rate hearings.	B1, Tab 3 Appendix C
RP-1999-0035 Aurora Township Project	Union shall track the revenues received from customer contributions, the level and pattern of customer attachments and the construction costs incurred relating to this project for filing in a future rates case and as may be required from time to time by the Board.	B1, Tab 3 Appendix C
EBA 883, 884, 885 EBC 290, 289, 288 South Bruce Expansion Project	Union shall establish a separate account to track revenues received from customer contributions and to report on the level of attachments and customer contributions received relating to this project, in a future rates case, and as may be required from time to time by the Board.	B1, Tab 3 Appendix C
EBLO 259 Port Elgin Southampton and Wiarton Area Project	Union is directed to establish a separate account to track revenues received from customer contributions and to report on the level of attachments and customer contributions received in future rates cases and as may be requested from time to time.	B1, Tab 3 Appendix C
EBLO 270 Parry Sound Project	Union shall establish a separate account to track revenues received from customer contributions and to report on the level of attachments and customer contributions received relating to this project, in future rates cases and as may be requested from time to time by the Board.	B1, Tab 3 Appendix C
RP-1999-0006 Colborne Township Project	Union shall track the revenues received from customer contributions, the level and pattern of customer attachments, and the construction costs incurred relating to this project for filing in a future rates case, and as may be required from time to	B1, Tab 3 Appendix C

Board File No.	Directive	Response
	time by the Board.	
RP-2003-0063	Union shall report annually on the outcome of using the hybrid method of forecasting normal weather heating degree days based on a weighting of the 30-year average forecast and 20-year trend forecast. Union shall also use the same hybrid forecast for operations planning as is used for all other purposes.	C1, Tab 1
RP-2003-0063	Union shall maintain records of transactions relating to the Discretionary Gas Supply Service (DGSS).	ongoing
RP-2003-0063	Union shall track the gains from dispositions of assets within its accounting system under generally accepted accounting principles for consideration of the allocation of proceeds from such dispositions in Union's next rates proceeding.	ongoing
EB-2010-0296	The Board directs Union to review the rate-making methodology of M12-X and C1 Kirkwall to Dawn as part of its rebasing in 2013.	H1, Tab 2
EB-2011-0038	Union shall monitor for and maintain records of all future utility storage space encroachments and provide such information in its rebasing application.	C1, Tab 6
EB-2011-0038	Union shall include evidence on transportation services for non-utility storage operations in its rebasing application.	H1, Tab 1

UNION GAS LIMITED

UNION GAS CONDITIONS OF SERVICE

The attached document, *Union Gas Conditions of Service*, is also posted on Union's website at uniongas.com. This document replaces Union's *Gas Service Guidelines for General Service Customers* which was last filed with the Board in the EB-2005-0520 proceeding (Exhibit A1, Tab 13, Schedule 1).

CHANGES SINCE LAST REVIEWED BY THE BOARD

The document filed in the EB-2005-0520 proceeding was updated on September 30, 2011 and filed in EB-2010-0280.

On June 29, 2011 the Board issued a Notice to Amend a Rule in which it proposed a number of amendments to the Gas Distribution Access Rule ("GDAR") (EB-2010-0280).

On July 18, 2011 Union submitted comments on the proposed customer service guidelines and agreed to document and publish its current customer services standards and practices in a Customer Service Policy by September 30, 2011. Union also agreed to implement all amendments within 12 months from the proposed September 30, 2011 in-force date. In accordance with its submission, Union's updated its *Union Gas Conditions of Service* and sent it to the Board as posted on the Company's website on September, 30, 2011.

On October 14, 2011 the Board issued a Notice of Amendment to a Rule in which it revised the coming into force date to April 1, 2012.

In its *Conditions of Service,* Union specified that the modifications to Union Gas' Conditions of Service would be implemented by March 1, 2012. Union's *Conditions of Service* would be updated when modifications were implemented.

Union implemented modifications to its *Conditions of Service* effective March 5, 2012 and filed a copy with the Board.

Union Gas

CONDITIONS OF SERVICE

Foreword

Union Gas is a distributor of natural gas in the province of Ontario. We are committed to serving our customers in a safe, reliable and efficient manner. This document has been prepared to explain, in a summary form, the conditions which govern our operations. It is intended that this communication will help us to better serve our customers.

Except as otherwise noted, the following conditions apply to all gas rates and gas service, by or with Union Gas (referred to as “us” or “we” throughout this document).

We reserve the right to modify, alter or amend these conditions and to make further and other conditions as experience may suggest and as we may deem necessary or convenient in the conduct of our business. These conditions do not supersede any terms and conditions agreed to in our contracts for gas supply with you.

Basic Terminology

British Thermal Unit (BTU)	The amount of heat required to raise the temperature of one pound of water 1 degree Fahrenheit at 60 degrees Fahrenheit.
Company	Union Gas – also referred to as “We” and “Us” throughout this document. Refers to Union Gas, and where appropriate, any member that provides you with Union Gas services or products.
Cubic Metre	One standard cubic metre of gas is the volume of the gas that occupies one cubic metre at a temperature of 15 degrees Celsius and an absolute pressure of 101.325 kPa. (One standard cubic metre equals 35.494 standard cubic feet).
Curtailment	An unplanned suspension of gas delivery caused by a physical failure or a high risk failure on our pipeline system, or non-delivery of gas into our pipeline system.
Customer	An individual, group of individuals, company or corporation responsible for the receipt and payment of goods and/or services provided by the Company. Referred to as “you” and “your” throughout this document.
Customer Service	Work done for you by our service personnel or authorized agents on behalf of us, including the installation and adjustment to meters and regulators and the associated appliance inspections.
Degree Days	A measure of the coldness of the weather experienced, based on the extent to which the daily mean temperature falls below the reference temperature of 18 degrees Celsius. A heating degree day is the difference between 18 degrees Celsius and the average temperature of the day. For example if the average given temperature on any given day is 10 degrees Celsius, then the number of degree days would be 8 (18-10). If the average temperature for the day is 18 degrees Celsius or higher, then the number of degree days for that day would be zero. As the weather gets colder the number of degree days increases. Union Gas uses degree days as a measure of coldness for comparative purposes. Generally the higher the degree days recorded, the higher the gas used on an account.
Gas	Natural gas or manufactured gas or liquefied petroleum gas or any mixture of these containing not less than 36 megajoules per cubic metre.
Gas Appliance	A device that consumes or is intended to consume a gas

	and is certified or field approved as acceptable to the provincial authority having jurisdiction.
Gas Sales Contract	A contract between the Company and a customer prescribing rates and conditions for the supply of gas, transportation and storage services to the customer.
Main	The pipe that is used to carry natural gas to a service.
Main Extension	The addition of pipe to an existing main to serve new customers.
Point of Delivery	The point(s) or points at the outlet side of our meter(s) at the location(s) where the gas is delivered to you.
Property Line	The Line that separates the boundary between one property and the next immediately adjacent property whether it is public or private.
Rate Schedule	One of a set of schedules filed with and approved by the Ontario Energy Board describing a category of customer, the rates charged for gas supplied to customers in the category and the particular terms under which gas is supplied to such customers. The rates determined by Union Gas and approved by the Ontario Energy Board that outlines the type of customer and the payment schedules for each of these customer types.
Service Lateral	Piping that conveys gas from a main to your meter.
Service	*Residential:* Customers supplied for residential purposes in a single family dwelling or building, or in an individual flat or apartment within a multiple family dwelling or building or a portion of a building occupied as the home, residence, or sleeping place of one or more persons. ▪ When service for residential purposes is supplied to two or more families served as a single customer under one rate classification contract that service is considered as commercial but is counted as only one customer. ▪ Residential premises also used regularly for professional or business purposes (such as doctor's office in a home or where a small store is integral with the living space), are considered as residential where the residential use of gas is half or more than half of the total service. *Commercial:* Applies to customers engaged in selling, warehousing or distributing a commodity, in some business activity or in some other form of economic or social activity (also includes professions). ▪ The size of the customer's operation or volume of use is not a criterion for determining Commercial service. *Industrial:* Customers engaged in a process which creates or changes raw or unfinished materials into another form or product, or who change or complete a semi-finished

material into a finished form.

- All gas used on premises which qualify under the industrial classification is to be classified as industrial service.
- The size of the customer's operation or volume of use is not a criterion for determining Industrial Service.

1. About our Area and Gas Services

1.1 Area Served by Company

As outlined in these conditions of service, Union Gas has an adequate supply of gas to serve its customers, and has properly installed pipe and piping according to the appropriate legislative requirements. Union Gas supplies gas to over 400 communities within the 230 municipalities where Union Gas holds a franchise agreement. These are considered traditional place names and may not in all cases reflect the current names of these communities.

Communities

Aberfoyle
Acton
Adelaide Twp
Ailsa Craig
Alberton
Aldborough Twp
Alma
Alvinston
Amabel Twp
Amherstburg
Amherstview
Ancaster
Appin
Arkona
Arran Twp
Artemesia Twp
Arthur
Arthur Twp
Astra
Atherley
Atikokan
Atwood
Awrey Twp
Ayr
Azilda
Baden
Baltimore
Barwick
Batawa
Bath
Bayfield
Bayham Twp
Beachville
Beardmore
Belleville
Bentinck Twp
Berwick
Bewdley
Blandford-Blen Twp
Banshard Twp
Blenheim
Blezard Valley
Blind River
Bloomfield
Bloomingdale
Blue Mountains
Blyth
Bosanquet Twp
Bothwell
Bracebridge
Branchton
Brant Twp
Brantford
Brantford Twp
Breslau
Brigden
Brighton
Brights Grove
Brockville
Brooke Twp
Brookville
Bruce Mines
Brussels
Burford
Burford Twp
Burgessville
Burks Falls
Burlington
Cache Bay
Caledonia
Callander
Calstock
Cambridge
Camden Twp
Camlachie
Campbellville
Canboro
Canborough Twp
Canfield
Cannifton
Capreol
Caradoc Twp
Cardinal
Carlisle
Carrick Twp
Castleton
Cathcart
Cayuga
Cayuga N Twp
Cayuga S Twp
Cedar Springs
Centralia
Centreton
Chaput Hughes
Charing Cross
Charlotteville Twp

Chatham
Chatham Twp
Chatsworth
Chelmsford
Chesterville
Clifford
Clinton
Cobalt
Cobourg
Cochrane
Colborne
Colborne Twp
Colchester N Twp
Colchester S Twp
Collingwood Twp
Conestogo
Coniston
Copetown
Copper Cliff
Corbyville
Cornwall
Corunna
Courtland
Courtright
Crediton
Crysler
Culross Twp
Cumberland Beach
Dashwood
Dawn Twp
Delaware Twp
Delhi
Derby Twp
Dereham Twp
Desbarats
Deseronto
Devlin
Dorchester
Dorchster N Twp
Dorion
Dover Centre
Dover Twp
Dowling
Downie Twp
Drayton
Dresden
Dryden
Duart
Dumfries N Twp
Dumfries S Twp
Dundas
DunnTwp
Dunnville
Dunwich Twp
Durham
Dutton
Ear Falls
Earlton
East Wawanosh Twp
Easthope N Twp
Easthope S Twp
Echo Bay
Eden
Egmondville
Egremont Twp
Ekfrid Twp
Elginburg
Ellice Twp
Elliot Lake
Elma Twp
Elmira
Elora
Emo
Englehart
Enniskillen Twp
Eramosa Twp
Erie Beach
Erieau
Espanola
Essex
Euphemia Twp
Exeter
Falconbridge
Fauquier
Fergus
Finch
Fisherville
Flamborough
Flamborough W Twp
Flesherton
Floradale
Florence
Forest
Fort Frances
Foxboro
Frankford
Freelton
Fullarton Twp
Gananoque
Garafraxa W Twp
Garden River
Garson
Georgetown
Geraldton
Glanbrook Twp
Glen Williams
Glencoe
Glenelg Twp
Goderich
Goderich Twp
Gosfield S Twp
Gowanstown
Grafton
Grand Bend
Gravenhurst
Greensville
Grey Twp
Guelph
Guelph Twp
Hagersville
Haileybury
Hallebourg
Halton Hills
Hamilton
Hanmer
Hanover
Harrisburg
Harriston
Harrow
Harty
Harwich Twp
Hawkesville
Hay Twp
Hearst
Heidelberg
Hensall
Hepworth
Hibbert Twp

Highgate
Hillier
Holland Twp
Holtyre
Hornell Heights
Howard Twp
Howick Twp
Hullett Twp
Huntsville
Hurkett
Huron Park
Ignace
Ingersoll
Ingleside
Inkerman
Innerkip
Inwood
Iron Bridge
Iroquois
Iroquois Falls
Jarvis
Jerseyville
Joyceville
Kakabeka Falls
Kapuskasing
Keewatin
Kenora
Kent Bridge
Keppel Twp
Kilbride
Kilsyth
Kilworth
Kilworth Heights
Kingston
Kingsville
Kirkland Lake
Kitchener
Komoka
La Salette
Lakeport
Lakeshore
Langton
Lasalle
Leamington
Levack
Linwood
Listowel
Lively
Lobo Twp
Logan Twp
Londesborough
London
London Twp
Long Sault
Longford Mills
Longlac
Lowbanks
Lowville
Lucan
Lynden
Lynedoch
Madoc
Maitland
Mannheim
Markdale
Markstay
Marmora
Maryborough Twp
Maryhill
Matheson
Mattawa
Mattice
Maynard
McGillivray Twp
McKillop Twp
Meaford
Merlin
Metcalfe Twp
Middleport
Middleton Twp
Mildmay
Millgrove
Milton
Minto Twp
Mitchell
Mitchell’s Bay
Monteith
Moonbeam
Moore Twp
Mooretown
Morewood
Morpeth
Morris Twp
Morrisburg
Morriston
Mosa Twp
Moulton Twp
Mount Brydges
Mount Elgin
Mount Forest
Mount Hope
Mount Pleasant
Murillo
Nairn Centre
Nanticoke
Napanee
Naughton
Neebing
New Dundee
New Hamburg
New Liskeard
Newburgh
Newbury
Nichol Twp
Nipigon
Nissouri W Twp
Norfolk Twp
Normanby Twp
North Bay
North Buxton
North Cobalt
Norval
Norwich
Norwich N Twp
Norwich S Twp
Norwich Twp
Novar
Oakland
Oakland Twp
Oakville
Odessa
Oil City
Oil Springs
Oliver Paipoonge
Onaping
Oneida Twp
Onondaga Twp
Opasatika

Orford Twp
Orillia
Orkney
Orland
Orrville
Otterville
Owen Sound
Oxford Southwest Twp
Paincourt
Palmerston
Paris
Parkhill
Parry Sound
Peacock Point
Peel Twp
Petersburg
Petrolia
Picton
Pilkington Twp
Pinewood
Plainfield
Plattsville
Plympton Twp
Point Edward
Porcupine
Porquis Junction
Port Dover
Port Elgin
Port Hope
Port Lambton
Port Rowan
Port Ryerse
Port Stanley
Port Sydney
Powassan
Prescott
Princeton
Puslinch Twp
Quinte West
Rainham Twp
Rainy River
Raleigh Twp
Rama
Ramore
Red Rock
Ridgetown
Rockwood
Rodney
Romney Twp
Rondeau Park
Roseville
Rothsay
Rutherglen
Salem
Sarawak Twp
Sarnia
Sauble Beach
Saugeen Twp
Sault Ste. Marie
Schumacher
Scotland
Seaforth
Sebringville
Selby
Selkirk
Seneca Twp
Shallow Lake
Shanty Bay
Sherbrooke Twp
Shrewsbury
Shuniah Twp
South Mountain
South Porcupine
South River
Southampton
Southwold Twp
Springford
St Agatha
St Andrews West
St Clements
St George
St Jacobs
St Marys
St Thomas
St Vincent Twp
St Williams
Stanley Twp
Stephen Twp
Stirling
Stockdale
Stoney Creek
Stratford
Strathroy
Stratton
Sturgeon Falls
Sudbury
Sullivan Twp
Sundridge
Swastika
Sydenham Twp
Tara
Tavistock
Tecumseh
Teeswater
Teeterville
Temagami
Thamesford
Thamesville
Thedford
Thessalon
Thornbury
Thorne
Thunder Bay
Tilbury
Tilbury E Twp
Tillsonburg
Timmins
Townsend
Townsend Twp
Trenton
Trout Creek
Tuckersmith Twp
Tupperville
Turnberry Twp
Tweed
Usborne Twp
Val Caron
Val Gagne
Val Rita
Val Therese
Vanastra
Vermilion Bay
Verner
Vickers Heights
Vittoria
Wahnapitae
Walkerton
Wallace Twp

Wallaceburg
Wallenstein
Walpole Twp
Walsingham
Walsingham N Twp
Walsingham S Twp
Wardsville
Warren
Warwick Twp
Waterdown
Waterford
Waterloo
Watford
Wellesley
Wellesley Twp
Wellington
West Lorne
West Montrose
Westbrook
Westlake
Westminster Town
Wheatley
Whitefish
Wiarton
Wilkesport
Williams E Twp
Williams W Twp
Williamsburg
Wilmot Twp
Winchester
Windham Twp
Windsor
Wingham
Winterborne
Woodhouse Twp
Woodlawn
Woodslee
Woodstock
Wooler
Woolwich Twp
Wyoming
Yarmouth Twp
York
Zone Twp
Zorra Twp
Zorra-Tavistock East
Zurich

1.2 Quality of Gas

The gas to be delivered shall be natural gas or its equivalent from our present or future sources of supply, and shall:

- Have a heating value of a minimum 36 megajoules per cubic metre
- Be commercially free from objectionable matter

NOTE: *The gas delivered to customers attached to field gathering lines may vary from pipeline quality gas due to local well conditions.*

1.3 Gas Distribution Services

Gas distribution services will be made available to all residential, commercial and industrial customers in all communities served by us:

- when we have determined transportation, distribution and/or storage capacity is available, and
- when we determine that the installation of gas piping (and related gas equipment) to serve you is economically feasible

Applying for more than one type of rate schedule

Customers may have gas distribution services under more than one rate schedule, as follows:

- Provided the customer meets all of the requirements for applicability, which are found in each rate schedule.
- This service may be taken through one meter, provided:
  - there is agreement upon a definite volume of gas that you will purchase under each rate
  - the volume of gas that falls under distribution charges, and
  - the delivery sequence

Gas Distribution Interruptions

Curtailment, or requests to stop gas use, may be required if the supply of gas is jeopardized, in the following situations:

- If there is an actual or threatened shortage of natural gas beyond our control
- When required because of curtailment or restrictions ordered by an authorized government authority

We assume no liability for any loss of production or for any damage whatsoever due to curtailment or discontinuance or because of the length of advance notice given that directs that curtailment or discontinuance.

1.4 Limitations of Liability

We shall use care and diligence to furnish sufficient gas distribution capacity but we assume no liability for damages or loss resulting from any failure of supply.

It is the customer's responsibility to provide and maintain:

- All pipes and valves to take the gas from the meter
- All equipment used in the burning of gas
- All vents necessary to efficiently take all products of combustion (including unburned gas if any) to the outside air

2. Initiation of Service

2.1 Main Extensions

We will extend our gas main within our franchise area to serve new customers (or potential customers) when:

- those requirements will not disturb or impair the service to prior users
- we determine the extension of the gas main is economically feasible

When we determine the extension of our facilities is not economically feasible, the applicant will be required to pay a contribution in aid of construction. We will determine the contribution amount before the extension of such facilities.

2.2 Service Lateral Installations

Service laterals will be installed provided that:

- There is an application for gas.
- The site of the service lateral installation is within our franchise area.
- Adequate distribution facilities are available.
- Any necessary main extension can be justified in accordance with our line extension practice.
- The requested hourly volume is available in accordance with the required supply pressure.
- In our sole discretion, we have an adequate gas supply to provide gas service.

We will designate the location of the service lines, meters and regulators, and will determine the amount of space that must be left unobstructed for the installation.

We do not assume ownership, responsibility or maintenance of piping beyond the outlet side of the meter or regulator set up.

If a customer wants us to install main on property that is not owned by the customer, such as road allowance, municipal or neighbouring property, land rights (in the form of easement) will be required for the installation / maintenance of gas lines (and equipment) from that property owner.

We shall try to restore property to the approximate condition in which it was found before starting our operations. This includes property that is excavated or may be disrupted during laying, constructing, repairing or removing our facilities.

2.3 Customer Costs

Gas service laterals extending from the property line to the meter location will be installed according to our policies and procedures. Customers are charged for these services as follows:

Residential Customers

- Billed for any excess charges beyond 30 metres

- Billed for aid as calculated using the Company's test of economic feasibility for service lateral extensions
- Billed for charges related to the installation of the meter set beyond our approved location.

Commercial and Industrial Customers

- Union Gas uses a Distribution Related Economic Analysis Model to cost Commercial and Industrial services. If the service does not meet an economic feasibility benchmark, a customer will be expected to pay aid to construction costs in order to meet our internal economic feasibility benchmark.
- If aid to construction is required, Union Gas will provide the costs to the customer, for approval prior to initiating the installation of the service

When the installation is effected by us, our cost is:

- Material used at inventory value (including appropriate stores expense).
- Cost of direct labour on installation (including appropriate payroll burden).
- Cost of transportation and mobile work equipment.
- Cost of contract work.

2.4 Relocation of Service Laterals

For service lateral relocations requests, the cost will be based on size and nature of any added gas that is required. Requested relocations for convenience or aesthetics will normally be on a charge basis.

We reserve the right to make changes, extensions, or replacements of service lines.

2.5 Customer Piping

As an applicant for service, a customer shall at their expense, equip premises with all piping and attachments from the meter to the appliances or equipment served. It is the customer’s responsibility to maintain the piping and equipment beyond the outlet side of the meter. Such piping and attachments shall be installed and maintained in accordance with the Ontario Regulation 212/01 – Gaseous Fuels, as amended.

If we know that the piping and/or appliances or heating equipment are defective, or not in accordance with applicable rules and regulations, ordinances or codes, we will not connect a meter.

We may discontinue gas service at any time that we find defective or unsafe conditions on:

- the piping
- the venting
- the appliances or other gas-fired equipment

Notification and Maintenance

If there is leakage or escape of gas on a customer’s premises, the customer is required to immediately notify Union Gas. The emergency number for Union Gas Limited is 1-877-969-0999.

Customers should ensure that their chimney or gas equipment venting system is clean and clear of obstructions.

If injury or damage occurs because of the escape of gas or products of combustion of gas from building piping, venting systems, or appliances on the customer's side of the Point of Delivery, we are not liable, unless the injury or damage can be traced to our negligence.

2.6 Meters and Meter Location

A meter or meters of standard manufacture, that we install (unless otherwise specified) shall measure the gas supplied. We will furnish each customer with a meter of a size and type that will adequately serve the customer's requirements. These meters are our property. We can inspect, remove or replace these as we deem necessary or in accordance with applicable rules, regulations, ordinances or codes.

Non-contiguous customer premises shall be metered and billed separately. Premises are considered non-contiguous when they:

- are not on the same tract of land
- are complete and not integrated with or part of other premises
- are integrated with or part of other premises

Tracts of land separated by public streets, roads, lanes or alleys shall be considered non-contiguous lands.

Residential, Commercial, Industrial meters will be located near a building, taking into consideration the following:

- safety
- distribution facilities
- customer equipment
- noise
- structural design
- landscaping
- accessibility for meter reading and servicing

Inside locations require the approval of the District Manager or designate.

Anyone who is not an authorized agent of the Company shall not be permitted to connect or disconnect our meters, regulators or gauges, or in any way alter or interfere with our meters, regulators or gauges.

Customers are responsible for protecting all metering and regulating equipment necessary for the supply of gas and for keeping it accessible at all times. Customers will be held liable for any such loss or damage beyond ordinary wear and tear, and if required, shall pay us the cost of necessary repairs or replacements.

We are not responsible for damages caused by the freezing of water pipes, water heaters and hot water systems in your premises unless the damage can be traced to our negligence.

2.7 Delivery and Use of Gas

Our gas delivery and the customer’s use of gas constitute a contract subject to these provisions, even if a contract has not been signed.

The place of delivery of all gas purchased under sales service, or redelivery in the case of direct purchase, shall be at the outlet of our meter located at or near the point or points of connection with the customer’s facilities. At that point all gas delivered shall become the customer’s property.

All gas passing through the meter, whether it is used or lost through leaks in pipes, apparatus, or otherwise is the customer’s responsibility and the customer shall pay for that gas.

Gas sold to non-contract customers at excess pressure shall be sold by the cubic metre corrected to a base temperature and pressure.

2.8 Inspection of New Installations

All inspections shall conform to the Technical Standards and Safety Act and regulations made under the Act.

An inspection will be made of new installations of supply piping and gas appliances and installations in accordance with Company practice as follows:

- where premises are connected to a supply of gas for the first time.
- in accordance with the requirements of the Technical Standards and Safety Act and the regulations made under the Act.

If the inspection reveals that repairs or major adjustments are required, the customer will be advised.

3. Maintenance of Service

3.1 Customer Service Policy Statement

Union Gas provides customers with specific and specialized service. The following services are provided free of charge:

- Emergency response
- Inspections mandated by applicable legislation
- Minor adjustment service to natural gas equipment (i.e. work that can be completed within 30 minutes and does not require any appliance parts, special tools or special equipment). Customers requiring additional appliance service will be advised to contact a third party service provider.

3.2 Access to Premises

Our authorized representatives shall have access to a customer's premises at all reasonable times and upon reasonable notice to inspect, read, test, repair, or replace the meter or meters, appliances and equipment used in connection with gas service.

3.3 Testing Meters

We will test meters when necessary, or:

- upon a customer's request
- when required to ensure accordance with legislative requirements.

If there is an unresolved dispute between two parties over meter accuracy, the test process must be initiated through Measurement Canada. This maintains the independence of the dispute process and requires the disputing party, normally the customer, to contact Measurement Canada directly.

Measurement Canada sets out Federal Regulations Union Gas must follow with regard to Gas Measurement. Union Gas is a fully accredited Gas Utility with authorization from the Federal Government to test and seal meters.

If a customer requests a meter accuracy check, and it meets the regulated accuracy requirements during the inspection, we may charge any additional cost for the meter removal and test. This is in addition to the Government inspection fee.

3.4 Resale Prohibited

Gas shall not be resold or redistributed (pursuant to the definitions of those terms in the OEB Act) directly or indirectly by the customer, except:

- gas purchased under the Company's Rate Schedule M1, M2, Rate 01 and Rate 10 for resale as motor vehicle fuel gas (as that term is defined in Ontario Regulation 805/82), or
- gas purchased under the Company's Rate Schedules M9 and M10 and Rate 77 by a customer, that is itself a distributor of natural gas.

4. Customer Care

Section 4 applies to any customer that has not entered into a Gas Sales Contract with Union Gas. For customers that have entered into a Gas Sales Contract with Union Gas, the terms and conditions set out in that contract will supersede the information contained within this section.

4.1 Establishing an Account

Whether a new customer or moving from an existing Union Gas account, customers should notify Union Gas before taking possession of a new home. Account requests can be submitted online or by phone at 1-888-774-3111. Accounts are subject to a one-time activation fee. Customers with Union Gas may be required to provide a security deposit. See section 4.11 for details.

Once delivery of gas to a premise has been established, a contract between the customer and Union Gas is in effect until delivery of gas is discontinued. The customer agrees to pay for services provided, and is liable for all gas supplied to the premises and for the safe custody of Union Gas property.

4.2 Meter Reading

Union Gas makes every effort to read all meters on a monthly schedule. Sometimes we estimate bills if inaccessibility or weather prevents us from reading the meter within a few days of the normal date.

Customers may elect to supply their own meter reading either online or by telephone at 1-888-774-3111. When submitted on a timely basis, these readings will be used in the monthly bill calculation.

If usage is estimated, any necessary adjustments will be included in the next actual meter reading.

On rare occasions, we may have to estimate a bill if the metering equipment malfunctions or has been damaged.

Commercial / industrial non-contract excess pressure customers' meters may be read daily or weekly.

4.3 Billings for Accounts

Consolidated Billing

Customers may combine several meters on to one gas bill if the meters are located on contiguous tracts of land not divided by a public right-of-way. In such cases, an additional service charge as specified in the current rate order shall be rendered each month for each of these meters.

Master Summary Billing

Master Summary Billing summarizes the invoices associated with multiple accounts on one Master Account. Customers choosing this option receive no more than four Master bills per month, depending on the number and location of meters included in their various individual accounts.

4.4 Bill issuance and Payment

Bills are issued on a monthly basis. Invoices are due when rendered and customers are provided a period of 20 days for payment before a Late Payment Charge is applied to their account. Both the invoice issue date and the Late Payment applicable date are printed on all invoices. Whether the customer is issued a paper or electronic invoice, the dates and timelines are the same.

Gas Charges are calculated using rates approved by the Ontario Energy Board.

Each monthly gas invoice will include a set 'monthly charge' that is a set amount charged to every customer regardless of the amount of gas used. It partially covers the cost of maintaining a safe gas distribution system 24 hours a day, every day. The monthly charge will be prorated on initial, final and seasonal invoices when the period covered by the bill is less than 25 days. The amount of the monthly charge is part of the approved Ontario Energy Board rate structure.

Invoices are due when rendered. Union Gas' billing and payment options include:

- **Automatic payment plan:**
  Automatically withdraw payment from your bank account.

- **Paperless billing:**
  Use Union Gas' free paperless billing option to receive your bill online.

- **Equal Billing Plan:**
  Enjoy the benefits of predictable monthly billings all year.

- **Combine Billing and Payment Options:**
  Bundle Paperless Billing, Equal Billing Plan and the Automatic Payment Plan to make monthly payments even more convenient.

Join our billing and payment options online or by telephoning 1-888-774-3111.

More payment options:

- Online banking through your financial institution
- Telephone banking
- Automatic Teller machine
- In person at most banks and financial institutions
- Pay your bill using your credit card online or through our automated telephone service at 1-888-774-3111. Please note that this credit card service is powered by Paymentus Corporation and is subject to a service fee of $3.25 for each payment up to $150.
- Mail your payment directly to Union Gas.

When payment of the monthly invoice has not been made in full 20 days after the bill has been issued, an Ontario Energy Board approved late payment charge equal to 1.5% (annual effective rate of 19.56%) of any unpaid balance, including previous arrears will be charged.

The Late Payment fee is not applied to unpaid security deposit amounts.

Payments are posted to customer accounts based on the day the payment is received. The date of receipt of mailed payment will be the postmark date on the envelope.

4.5 Allocation of Payments between gas and non-gas charges

Payments are applied to charges based on date (oldest paid first), then based on the priority for additional charges incurred at the same time.

For any charges in arrears, payment will be applied to the oldest charge first and Late Payment fees will be applied to the outstanding balance.

Union Gas does not provide joint billing services for rentals or third party services.

4.6 Correction of Billing Errors

If a billing error occurs, customers should contact our Customer Contact Centre at 1-888-774-3111 to request a billing investigation.

With the exception of tampering or theft of gas:

- If the error resulted in over-billing, it will be corrected for a period of up to two years. The customer may request a refund or opt to leave the credit amount on their account to cover future bills.
- If the error resulted in under-billing, it will be corrected for a period of up to one year. If required, Union Gas will work with the customer to determine a mutually agreeable repayment schedule.
- If the time period cannot be reasonably determined, the error will be corrected for a period of up to three months.

4.7 Equal Billing Plan

The Equal Billing Plan offers residential customers the convenience of equal payments throughout the year. Using your total natural gas usage for the previous year and current gas rates, we calculate your total expected gas bills and divide it into equal monthly instalments. In August of each year your EBP is “trued up” and your account is credited or billed for any difference between the EBP instalments that you have paid and the gas you’ve used.

Your account is reviewed periodically and your monthly EBP instalment may be adjusted up or down. Factors that can impact your EBP instalment include significant changes in the weather, gas rates or the amount of gas used.

If you cancel the Equal Billing Plan before the August true up, or if you move from your residence, the plan will be automatically trued up at that point and your account will be billed or credited for the difference between the EBP instalments paid and the cost of the gas you have used.

Each August, your gas usage for the previous year is reviewed to determine your new instalment amount for the coming plan year. You will be automatically re-enrolled in the plan in September for the next 12 months at your new monthly instalment amount.

4.8 Discontinuance of Gas Delivery – Customer Initiated

Customers who require a temporary disconnection of their gas service should contact Union Gas at 1-888-774-3111. During the temporary disconnection, customers must either continue to pay the monthly fixed charge or pay a disconnection and reconnection fee.

4.9 Disconnection for Non-payment

If any charges remain unpaid after the date shown on the invoice, Union Gas has the right to discontinue delivery of gas service.

Residential Accounts - If the customer does not initiate action to manage their arrears, delivery may be discontinued after giving 10 days written notification through a Disconnection Notice to the customer. The Disconnection Notice will indicate the earliest and latest date on which the disconnection will occur, provides payment options to avoid the disconnection of service and indicates that the disconnection can take place without further notification to the customer. In determining whether to issue a disconnection notice or to pursue additional payment arrangements with the customer, Union Gas will take into account any paid security deposit that is being held on the customer's account.

Non Residential Accounts - If the customer does not initiate action to manage their arrears, delivery may be discontinued after giving prior notification through a message on the bill or through other written notification to the customer. In addition to a bill message or written notification, Union Gas attempts to reach the customer by telephone prior to issuing a disconnect order.

At any time prior to service disconnection, a customer can make a payment at a financial institution, through Internet or telephone banking or by credit card, to cancel the disconnection order.

If during the disconnection notice period, a third party, who has been designated by the customer, or a registered charity, government agency or social service agency, advises Union Gas that they are attempting to arrange assistance to help the customer pay their outstanding arrears, Union Gas will cancel the disconnection order and will delay further action for 21 days. If mutually agreeable payment arrangements are created during this process, but are subsequently missed, the account may be disconnected without further notice.

Once the account is paid in full, including any reconnection charges or security deposit required, Union Gas reconnects gas service for the account within two business days.

4.10 Discontinuance of Gas Delivery for other than Non-payment

If we need to temporarily discontinue delivery of gas for meter maintenance, a meter change or line maintenance, Union Gas will make arrangements with the customer in advance as we will need access to the premises to relight and inspect the gas appliances. For safety reasons, gas service cannot be reinstated until this inspection is completed by one of our qualified technicians.

Note: *The above inspections are free, however, if the inspection is carried out at the request of a third party (i.e., lawyer, real estate broker, etc.) then the customer will be charged for the inspection.*

We may **discontinue service at any time for emergency or safety reasons** including:

- a gas leak or potential safety issue in your neighbourhood
- fraudulent use of gas
- any condition affecting appliances or piping which we believe is dangerous to life or property
- the use of gas for any purpose other than that described in the service application, gas sales contact, rate schedule or these rules and regulations
- if we are refused access for any lawful purpose to the premises to which gas is supplied
- when a customer tampers with, damages or destroys our property on their premises

4.11 Security deposits

If you are a new customer to Union Gas or if future payment cannot be assured, you are required to provide a security deposit.

Residential Customers - The deposit will be equal to two of the average month's gas usage based on the last 12 months usage history. Customers are provided the option to pay the security deposit over a maximum of six monthly instalments without interest.

In the majority of cases, Union Gas will waive the security deposit if the customer enters into both the Equal Billing Plan and the Automatic Payment Plan or provides a letter of reference with a good rating from a Canadian natural gas or hydro utility dated within the past 60 days.

Deposits are automatically refunded with interest to the customers' account once the deposit has been paid in full and the customer has exhibited twelve months of good payment history. When the deposit is applied, the customer has the option of leaving the credit amount on their account for future bills or requesting a refund.

Non-Residential Customers - The deposit amount will be a maximum of the three highest consecutive months' usage history or $500.00 if there is insufficient historical usage information for the premises. The deposit is refunded with interest after five years of exhibiting financial stability through a good payment history.

The security deposit may be waived if the customer meets certain criteria.

Acceptable types of security deposits are as follows:

- Money orders or certified cheques
- Letter of Guarantee such as a guarantee of customer payment by a financial institution.

If you do not provide the requested security deposit, delivery of gas will be discontinued. Once the account is paid in full, including the outstanding security deposit, the reconnection charge and any arrears, Union Gas will reconnect the gas service within two business days.

All monetary deposits earn simple interest based on the current bank savings rate. The interest is calculated monthly.

When the customer moves or discontinues gas service, the security deposit is applied to the customer's account.

4.12 Arrears Management Programs

Union Gas has arrears management programs available to customers who are unable to pay their gas charges. Union Gas works with customers to find mutually agreeable payment plans that could extend up to several months depending on the individual circumstances. Customers requiring payment assistance can contact a Union Gas representative at our contact centre by telephoning 1-888-774-3111.

Union Gas will contact the customer, to remind them of required payments under an agreed upon payment arrangement 10 days prior to cancellation of the arrangement and further collection action.

Customers are advised at the time of the arrangement the importance of keeping the payments up to date to avoid further collection action.

4.13 Management of Customer Accounts

Union Gas will verify the identity of a customer prior to discussing account specific information. In accordance with applicable privacy laws, any personal information related to the account will only be shared with the party named as the customer on the account, unless written or verbal consent is provided by the party named as the primary customer on the account.

Union Gas will accept notification to transfer service to a third party name from vendors, purchasers, builders, vendor or purchaser solicitors, power of attorney or property owner/manager or housing administrator. Landlord instructions are maintained with direction from the owner on the management of gas service during a property vacancy and this direction is followed in the absence of a tenant contract. We do not accept new tenant information from vacating tenants.

4.14 Customer Complaint Policy

Step 1: Call Union Gas

Call the Union Gas Customer Contact Centre at 1-888-774-3111, Monday through Friday between 8:00 a.m. and 6:00 p.m. All Union Gas representatives are trained to help answer your questions.

You may also send us an email at uniongas.com/residential/contactus

Step 2: Escalating your Concern

If you have a problem or concern that has not been satisfactorily resolved by our representatives, you may ask to further escalate your concern. Please be advised that you will be required to leave your name and a phone number where you can be contacted. A Union Gas representative will return your call within 2 business days.

Step 3: Submit your Complaint in Writing

Union Gas will respond to all written customer complaints by e-mail or in writing (unless otherwise agreed to by the customer) within 10 calendar days.

Written complaints can be mailed to:

Union Gas Limited
P.O. Box 2001
50 Keil Drive North
Chatham, Ontario
N7M 5M1

For further information on our written complaints policy, please visit Customer Complaint Policy.

If your problem has not been resolved to your satisfaction, you can contact the OEB.

UNION GAS LIMITED

SCHEDULE OF SERVICE CHARGES

CHANGES SINCE LAST REVIEWED BY THE BOARD

The attached *Miscellaneous Non-Energy Charges* schedule was last approved by the Board in the EB-2010-0148 Rate Order (at Appendix E). Union is not proposing any changes to this fee schedule in this proceeding.

UNION GAS LIMITED
Miscellaneous Non-Energy Charges

Line No.	Service	Fee
	Residential Customer Class Service	
1	Connection Charge	$35
2	Temporary Seal - Turn-off (Seasonal)	$22
3	Temporary Seal - Turn-on (Seasonal)	$35
4	Landlord Turn-on	$35
5	Disconnect/Reconnect for Non-Payment	$65
	Commercial/Industrial Customer Class Service	
6	Connection Charge	$38
7	Temporary Seal - Turn-off (Seasonal)	$22
8	Temporary Seal - Turn-on (Seasonal)	$38
9	Landlord Turn-on	$38
10	Disconnect/Reconnect for Non-Payment	$65
	Statement of Account/History Statements	
11	History Statement (previous year)	$15/statement
12	History Statement (beyond previous year)	$40/hour
13	Duplicate Bills * (if processed by system)	No charge
14	Duplicate Bills * (if manually processed)	$15/statement
	Dispute Meter Test Charges	
15	Meter Test - Residential Meter	$50 flat fee for removal and test
16	Meter Test - Commercial/Industrial Meter	Hourly charge based on actual costs
	Direct Purchase Administration Charges	
17	Monthly fee per bundled t-service contract or unbundled U2 contract	$75.00
18	Monthly per customer fee	$0.19
19	Invoice Vendor Adjustment (IVA) fee (for each successfully submitted IVA transaction)	$1.09

Notes:

* Duplicate bill charges only apply when customer wants two copies of a bill. Lost bills from the last billing period will be replaced free of charge.

UNION GAS LIMITED

LIST OF WITNESSES

Witness	Title	Topic	Exhibit Number	
Doug Alexander	Director Engineering Design and Execution	Integrity Management/Storage Capital	B1, Tab 6	
Wes Armstrong	Director Distribution Operations Support	Distribution Expansion Overview	B1, Tab 4	
Tom Arnold	Director Communications and Community Investment	Community Investment	D1, Tab 8	
Tanya Bell	Public Affairs Community Investment Specialist	Community Investment	D1, Tab 8	
Bohdan Bodnar	Vice-President Human Resources Canada	Human Resources	D1, Tab 3	
Keith Boulton	Director Energy Conservation Strategy	Demand Side Management	D1, Tab 5	
Michael Broeders	Manager Financial Planning & Forecasting	Rate Base Overview	B1, Tab 1	
		Lead/Lag Study	B1, Tab 8	
		Cost of Capital/Rate of Return	E/F	
Carol Cameron	Manager Capacity Management & Utilization	S&T Forecast	C1, Tab 3	
		Integrity Space	D1, Tab 9	
Darrin Canniff	Director Planning & Forecasting	Rate Base Overview	B1, Tab 1	/u
		Lead/Lag Study	B1, Tab 8	/u
		Cost of Capital/Rate of Return	E/F	/u
Chuck Conlon	Director Employee and Labour Relations East	Human Resources	D1, Tab 3	
Beth Cummings	Manager O&M and Capital Reporting	Capital Budget Overview	B1, Tab 2	
		O&M Budget Overview	D1, Tab 2	
Pat Elliott	Controller	Human Resources	D1, Tab 3	
		Deferral Accounts	H1, Tab 4	
Mary Evers	Manager Gas Supply	Gas Supply	D1, Tab 1	
Bill Fay	Manager Underground Storage	Integrity Space	D1, Tab 9	
Paul Gardiner	Manager Demand Forecasting and Analysis	General Service Forecast	C1, Tab 1	
		Contract Forecast	C1, Tab 2	
		Weather Normalization	C1, Tab 5	
Bryan Goulden	Manager Market Development	Energy Technology and Innovation Canada	D1, Tab 10	
Dave Hockin	Manager Affiliate Reporting and Accounting	Affiliate Transactions	D1, Tab 7	
Tina Hodgson	Manager Asset Acquisitions	Gas Supply	D1, Tab 1	
Ken Horner	Senior Tax Specialist	Tax	D1, Tab 4	

UNION GAS LIMITED

LIST OF WITNESSES

Witness	Title	Topic	Exhibit Number	
Jim Laforet	Manager Contract Billing and Operational Support	Administration Fees	H1, Tab 3	
Cheryl Newbury	Manager Distribution Revenue	Other Revenue Forecast	C1, Tab 4	
Jeff Okrucky	Director Distribution Marketing	Customer Attachments	B1, Tab 3	
Mike Packer	Director Information Systems	Information Technology Capital	B1, Tab 7	
Harold Pankrac	Team Lead Rates & Pricing	Rate Design	H1, Tab 1	/u
Libby Passmore	Manager Strategic Sales	General Terms and Conditions	H1, T2	
Patti Piett	Director Storage Transmission Sales	S&T Forecast	C1, Tab 3	/u
Drew Quigley	Manager Gas Supply Planning	Gas Supply	D1, Tab 1	
Jim Redford	Director Business Development	Parkway West	B1, Tab 9	
David Richards	Manager Governance & Reporting	Producitivity	A2, Tab 5	
Chris Shorts	Director Gas Supply	Gas Supply	D1, Tab 1	/u
Robin Stevenson	Team Leader Product and Services Costing	Cost Allocation	G	
Greg Tetreault	Manager Rates & Pricing	Cost Allocation	G	
		Rate Design	H1, Tab 1	
Paul Trombley	Manager Capital Reporting	Capital Budget Overview	B1, Tab 2	
Sarah VanDerPaelt	Director Sales, Business Markets	Contract Forecast	C1, Tab 2	
Linda Vienneau	Manager Plant Accounting	Rate Base Overview	B1, Tab 1	
		Depreciation Study	D1, Tab 6	
Matt Wood	Manager System Planning	Transmission Facilities Projects	B1, Tab 5	

Statement of Qualifications
Doug Alexander

Experience:	**Union Gas Limited**
	Director, Engineering Design Execution 2009
	Director, Operations Technical Support (Engineering) 2005
	General Manager, Storage and Transmission Operations 1996
	Centra Gas
	General Manager, Central Area 1994
	Chief Engineer 1990
	Manager, Operations Technical Services 1988
	Senior Project Engineer 1985
	Operations Engineer 1980
Education:	Bachelor of Engineering Science (Civil), University of Western, London, Ontario 1980
Memberships:	Professional Engineers Association of Ontario
Appearances:	**(Ontario Energy Board)** EB-2008-0411 EB-2007-0520 EBRO 489 EBRO 483/484 EBRO 471 EBLO 247 EBLO 233 EBLO 208

Appearances: **(Ontario Energy Board) (cont'd)**
EBLO 201
EBA 447
EBA 628
EBA 629

Statement of Qualifications
Wes Armstrong

Experience: **Union Gas Limited**

Director, Distribution Operations
2010

Manager, Operations Support & Admin
2008

District Manager, London & Sarnia
2006

Manager, Distribution Operations Technical Support
2004

Utility Services Manager, London
2002

Senior Operations Engineer
2000

Operations Engineer
1998

Gas Control Planning Engineer
1997

Natural Resource Gas Limited (NRG)

Planner & Designer
1995

Education: Bachelor of Engineering Science (Civil), University of Western, London, Ontario
1995

Land Survey Technician Diploma, Fanshawe College, London, Ontario
1990

Memberships: Professional Engineers Ontario

Appearances: None

Statement of Qualifications
Tom Arnold

Experience: **Union Gas Limited**

Director, Communications and Community Investment
2011

Director of Public Affairs
2010

Minister of Energy and Infrastructure, Deputy Premier
Government of Ontario

Director of Communications
2008

Minister of Health and Long-Term Care, Deputy Premier
Government of Ontario

Director of Communications
2007

CV Technologies Inc.

National Communications Manager
2006

A1Communications

Communications/Public Affairs/Media Consultant
2003

National Post

Senior National Reporter
1998

Edmonton Journal

Provincial Affairs Reporter
1991

Education: Post Graduate Diploma in Business Administration, University of Liverpool, 2007

Master's of Journalism, Carlton University, 1992

Bachelor of Arts (Communications, Political Science) Simon Fraser University, 1988

Appearances: None

Statement of Qualifications
Tanya Bell

Experience: **Union Gas Limited**

Communications and Community Investment Specialist
2011

RBC

Manager Community Initiatives
2007

TD Bank Financial Group

Western Regional Manager, TD Friends of the Environment Foundation
2005

TD Canada Trust
Regional Coordinator, Staffsmart
2003

TD Canada Trust
Customer Service Manager
2001

Education: Certificate in Corporate Citizenship Management, Boston College
2011

2 years Business Administration, University of Alberta
1989

Appearances: None

Statement of Qualifications
Bohdan Bodnar

Experience: **Westcoast Energy Inc.**

Vice-President, Human Resources Canada
2002

Vice-President, HR & Administration
1999

Vice-President, Human Resources
1998

Vice-President, Human Resources & Admin
1998

Union Gas Limited

Vice-President, Human Resources
1994

Centra Gas British Columbia Inc.

Vice-President, Corporate Services
1992

Director, Human Resources
1990

Centra Gas Alberta Ltd.

Manager, Human Resources
1981

TransCanada Pipelines

Various Operations and Administrative Positions
1975

Education: Bachelor of Arts, University of Manitoba,
1976

Advanced Industrial Relations Certification, Dalhousie University
1985

Memberships: Canadian Gas Association

American Gas Association

Canadian Society of Safety Engineering

Human Resources Professionals Associations of Ontario

Canadian Association of Human Resources Systems Professionals

Appearances: **(Ontario Energy Board)**
RP-2003-0063
E.B.R.O. 493/494
E.B.R.O. 486

Statement of Qualifications
Keith Boulton

Experience: **Union Gas Limited**

Director, Energy Conservation Strategy
2011

Director, Distribution Marketing
2005

Manager, Residential Sales
2003

Manager, Residential, Commercial, Industrial Sales North East
2002

Manager Commercial/Industrial Sales North East
2000

Union Energy

Sales Manager, C/I Markets
1999

Manager Engineering Services
1997

Education: Masters of Business Administration,
Edinburgh Business School, Scotland,
2005

Bachelor of Sciences, Chemical Engineering, University of Waterloo,
1992

Memberships: Professional Engineers Ontario

American Society of Heating, Refrigeration and Air Conditioning

Engineers, Canadian Marketing Association

Appearances: **(Ontario Energy Board)**
EB-2008-0106
EB-2005-0520

Statement of Qualifications
Michael Broeders

Experience: **Union Gas Limited**

Manager, Financial Planning and Forecasting
2009

Manager, Product & Services Costing
2004

Manager, Financial Reporting
2002

Team Lead, Finance
1999

Coordinator, Financial Reporting
1997

Internal Auditor
1996

Coopers & Lybrand (now PriceWaterhouseCoopers)
Associate
1993

Education: Chartered Accountant
1995

Bachelor of Math, University of Waterloo
1992

Memberships: Canadian Institute of Chartered Accountants

Institute of Chartered Accountants of Ontario

Appearances: **(Ontario Energy Board)**
EB-2008-0106
EB-2005-0551
EB-2004-0542
RP-2003-0063

State of New York State Public Service Commission,
Case 01-G-1406, Proceeding on Motion of the Commission to Review Tariff Filing of Empire State Pipeline to Recover Deferred and Permanent Increase in Taxes

Statement of Qualifications
Carol Cameron

Experience: **Union Gas Limited**

Manager Capacity Management and Utilization
2011

Manager Strategic Sales
2007

S&T Specialist
2005

Buyer, Asset Acquisition
2004

Senior Analyst, Finance
2003

S&T Account Manager
2000

Customer Service Representative
1998

S&T Nominations Analyst
1996

Education: Bachelor of Commerce, University of Windsor, 1993

Appearances: **(Ontario Energy Board)**
EB-2011-0038
EB-2005-0201
EB-2005-0551

Statement of Qualifications
Darrin Canniff

Experience:	**Union Gas Limited**
	Director Planning and Forecasting 2012
	Director, Strategic Development 2006
	Manager, Financial Analysis 2001
	Manager, Gas Supply Accounting and Accounts Payable 1997
	Financial Specialist Business Development 1996
	Corporate Tax Specialist 1994
	KPMG - London 1989
Education:	Certified Public Accountant 2003
	Chartered Accountant 1991
	Bachelor of Business Administration, Wilfrid Laurier University 1989
Memberships:	Institute of Chartered Accountants of Ontario
	Canadian Institute of Chartered Accountants
	Illinois Certified Public Accountant Society
Appearances:	None

Statement of Qualifications
Chuck Conlon

Experience:	**Union Gas Limited**
	Director, Employee and Labour Relations 2002
	Canadian General Tower
	Vice-President Human Resources – NA 1999
	IHDG
	Director Human Resources – Canada 1998
	Sunworthy Wallcoverings
	Director Human Resources - NA
	Director Human Resources - Canada 1987-1998
	McDonnell Douglas Canada Ltd.
	1981-1987
Education:	Bachelor of Arts, University of Toronto 1978
	Masters of Industrial Relations, University of Toronto 1985
Memberships:	Conference Board of Canada Human Resource Executive Council
	Human Resource Professional Association of Ontario
Appearances:	None

Statement of Qualifications
Beth Cummings

Experience: **Union Gas Limited**

Manager, O&M and Capital
2010

Manager, Culture & Change Management
2008

Manager, Operations Support
2004

Manager, Operations Services
2002

Project Manager, Upstream Regulation
2002

Manager, IT Services
2000

Manager, Project Management Office
1999

Bell Canada

Director, IT Project Management Office
1996

Associate Director, Engineering
1995

Section Manager, Network Traffic
1993

Manager, Network Traffic
1988

Education:	Enrolled in Certified Management Accounting (CMA) 2012
	Project Management Professional (PMP) 2001
	Masters of Business Administration (MBA), Queens University 1996
	Bachelor of Science (MSc), Windsor University 1988
Memberships:	Project Management Institute (PMI)
	Certified Management Accounting Society
Appearances:	None

Statement of Qualifications
Pat Elliott

Experience: **Union Gas Limited**

Controller
2008

Director, Accounting and Internal Controls
2007

Director, Accounting
2002

Controller
1999

Manager, Financial Planning
1997

Manager, Rates and Cost of Service
1995

Manager, Rate Design and Cost of Service
1989

Supervisor, Cost of Service Studies
1987

Supervisor, Plant Accounting
1985

Supervisor, Accounting Systems
1983

Senior EDP Auditor
1981

Clarkson Gordon - London
1977

Education: Chartered Accountant - 1981

Bachelor of Mathematics, University of Waterloo
1980

Memberships: Institute of Chartered Accountants of Ontario

Canadian Institute of Chartered Accountants

Appearances: **(Ontario Energy Board)**

EB-2011-0038
EB-2010-0039
EB-2008-0408
EB-2008-0273
EB-2007-0598
EB-2005-0211
EB-2005-0520
RP-2003-0063
RP-2002-0130
RP-2001-0029
RP-1999-0017
E.B.O. 195
E.B.R.O. 499
E.B.R.O. 493/494
E.B.R.O. 486-04
E.B.R.O. 486-03
E.B.R.O. 486-02
E.B.R.O. 486
E.B.L.O. 246
E.B.R.O. 476-06
E.B.R.O. 476-05
E.B.R.O. 476-03
E.B.R.O. 476-02
E.B.R.O. 478
E.B.R.O. 476-01
E.B.R.O. 470
E.B.R.O. 462
E.B.R.O. 412-III
E.B.L.O. 230
E.B.L.O. 234

Statement of Qualifications
Mary Evers

Experience:	**Union Gas Limited**
	Manager, Gas Supply 2011
	Team Lead, Gas Management Services 2009
	Manager, Billing and Operational Support 2000
	Team Lead, Fulfilment Support Services 1999
	Coordinator, Rate Case Administration, Regulatory 1997
	Regulatory Accounting Analyst 1995
Education:	Various Management and Accounting Courses, University of Windsor
Appearances:	None

Statement of Qualifications
Bill Fay

Experience: **Union Gas Limited**

Manager, Underground Storage (Canada)
2002

Westcoast Energy, Inc.

Manager, Storage & Transportation Projects
1999

St. Clair Pipelines Ltd.

Manager, Storage Projects
1993

Union Gas Limited

Manager, Storage Planning
1989

Senior Storage Planning Engineer
1985

Storage Planning Engineer
1981

Assistant Distribution Planning Engineer
1980

Education: B.Sc. Civil Engineering, University of Waterloo,
1980

Memberships: Registered Professional Engineer in the Province of Ontario

Ontario Petroleum Institute – Board of Directors - Past President

Appearances:	**(Ontario Energy Board)** RP-2003-0063 EBRM 101 EBLO 239 EBO 172 EBRM 95-1 EBRM 95 EBRM 94 EBRM 91 EBRM 88 PL 54 EBRM 85 EBRM 83

Statement of Qualifications
Paul Gardiner

Experience: **Union Gas Limited**

Manager, Demand Forecasts & Analysis
Core Markets 1999

Manager, Revenue Forecasts
1993

Standard Life Assurance Company

Sales Representative
1992

SaskEnergy – Regina, Saskatchewan

Director of Marketing
1988

SaskPower – Regina, Saskatchewan

Manager of Demand Forecasts: Gas & Electric
1984

Alberta Power – Edmonton, Alberta

Economist-Statistician-Demand Forecasts
1978

Government of Canada - Edmonton, Alberta

Labour Force Analyst
1976

Education: Economics, M.A, McMaster University, Hamilton, Ontario
1976

Economics, B.A. Honours, University of Winnipeg, Winnipeg, Manitoba
1975

Memberships: None

Appearances: **(Ontario Energy Board)**

EB-2007-0606
EB-2005-0520
RP-2003-0063
RP-2000-0110
E.B.L.O. 267
E.B.L.O. 251

Statement of Qualifications
Bryan Goulden

Experience: **Union Gas Limited**

Manager, Market Development
2010

Manager, Utilization Technology and Deployment
2007

Manager, Regulatory Applications
2002

Manager, Integrated Supply Planning
1999

Manager, Delivery Services Development
1997

Manager, Technology Marketing
1995

Manager, NGV Operations
1993

Manager, Industrial Sales Support
1987

Contract Gas Sales Engineer
1984

Coordiantor Contract Administration
1983

Gas Supply Analyst
1982

Education: Bachelor of Applied Science (Mechanical Engineering), University of Waterloo
1982

Masters of Business Administration, University of Windsor
1992

Memberships: Professional Engineers Ontario

Appearances: **(Ontario Energy Board)**
E.B.R.O. 470
E.B.R.O. 476-01
E.B.R.O. 476-03
E.B.O. 169-II

Statement of Qualifications
Dave Hockin

Experience: **Union Gas Limited**

Manager, Affiliate Accounting and Reporting
2010

Manager Affiliate Relations
2005

Team Lead Product Development
2001

Administrator, Financial Analysis
2000

Manager, Market Development and Project Management
1998

Strategic Planning
1996

Manager, Distribution Business Development
1995

Manager, Direct Purchase Development / Gas Distribution
Expansion, 1993

Sales Manager, Windsor Division
1990

Manager, Direct Purchase
1988

Co-ordinator, Direct Purchase
1986

Dome Petroleum - Calgary

Sulphur Supply and Sales Representative
1984

Experience (cont'd)	Co-ordinator NGL Operations - Marketing 1981
	Traffic Analyst 1980
Education:	Bachelor of Arts (Economics), Wilfred Laurier University, 1979
	Certified General Accountant 2005
Memberships:	Certified General Accounting
Appearances:	**(Ontario Energy Board)** EBRO 499 EBRO 493/494 EBRO 484 EBLO 252 et al/EBLO 254 et al EBLO 253/EBC 225-233/EBA 700-708 EBRO 486/EBO 177-07 EBC 213/EBA 687 EBLO 248/EBC 207/EBA 676 EBC 210/EBA 680 EBC 209/EBA 679 EBC 208-01/EBA 678-01 EBC 208/EBA 678 EBC 206/EBA 670 EBRO 476 (Direct Purchase) EBRO 462 EBRO 456-4 EBRO 456 EBRO 412-III

Statement of Qualifications
Tina Hodgson

Experience: **Union Gas Limited**

Manager, Transportation Acquisition
2010

Business Development Manager
2008

Buyer, Asset Acquisitions
2005

Project Manager & Product Developer, Product and Service Development
2001

Team Leader, Financial Analysis
2001

Primus Telecommunications Canada Inc.

Vice-President Operations, Local Provisioning
1997

123566 Ontario Inc.

Telecommunications Consultant
1994

Smart Talk Network Inc.

Vice-President Optimization and Regulatory
1992

Education: Masters of Business Administration, York University
1991

Honours Business Administration, Wilfrid Laurier University
1988

Memberships: Project Management Professional
2004

Appearances: None

Statement of Qualifications
Ken Horner

Experience: **Union Gas Limited**

Senior Income Tax Specialist
2008

Manager, Financial Forecasts
2003

Manager, Revenue and Gas Accounting
2001

Manager, Financial Planning
1999

Supervisor, Financial Forecasts
1996

Coordinator, Financial Forecasts
1995

Centra Gas Limited

Revenue Forecast Analyst
1994

General Accountant
1993

Education: CICA In-depth Tax – Part 2
2011

CICA In-depth Tax – Part 1
2010

Certified Management Accountant
1998

Bachelor of Arts – Commerce Specialist, University of Toronto,
1991

Memberships: The Society of Management Accountants of Ontario

Appearances: **(Ontario Energy Board)**
RP-2003-0063
RP-2002-0130
RP-2001-0029

Statement of Qualifications
Jim Laforet

Experience:	**Union Gas Limited**
	Manager, Contract Billing and Operational Support 2008
	Manager, Customer Care Support & Administration 2005
	Manager, Affiliate Relations 2002
	Manager, Billing Support 1999
	Internal Audit Manager 1995
	Supervisor, Internal Audit 1992
	Internal Auditor 1989
	CIBC
	Branch Administration Officer 1985
Education:	Master of Business Administration, University of Windsor, 1994
	Honours, Bachelor of Commerce, University of Windsor, 1985
Appearances:	**(Ontario Energy Board)** EB-2008-0150 EB-2007-0599 RP-2003-0063

Statement of Qualifications
Cheryl Newbury

Experience: **Union Gas Limited**

Manager, Distribution Revenue
2010

Manager, Strategic Sales Service
2005

Manager, Capacity Management and Utilization
2002

St. Clair Pipelines (1996) Ltd.

Business Manager
2001

Union Gas Limited

Manager, Asset Acquisition
1998

S&T Account Manager / Account Representative
1994

Shell Canada Limited

1988

Education: Honours Bachelor of Business Administration, Wilfrid Laurier University, 1988

Appearances: None

Statement of Qualifications
Jeff Okrucky

Experience: **Union Gas Limited**

Director, Distribution Marketing
2011

Manager, Strategic Support, Marketing and Customer Care
2006

Manager, Operations, London/Sarnia District
2004

Manager, District Workload Planning
1999

District Manager, London
1999

Manager, Operations Services
1999

Manager, Solutions Realignment Project
1997

Project Manager, Meter Shops/Warehousing
1995

Manager, Customer Service
1990

Supervisor, Planning and Dispatch
1988

Personnel Supervisor, Northern Region
1987

Coordinator, Operations Development
1986

Operations Technician
1984

Draftsperson
1979

Experience (cont'd) Mapping Clerk
1978

Education: Various part time credits or programs at St. Clair College, Fanshawe College, Wilfrid Laurier University, Queens University

Memberships: Certified Engineering Technician: Ontario Association of Certified Engineering Technicians and Technologists

Appearances: None

Statement of Qualifications
Mike Packer

Experience: **Union Gas Limited**

Director, Information Systems
2012

Director, Planning and Forecasting
2008

Director, Regulatory Affairs
2004

Manager, Regulatory Initiatives
2002

Manager, Rates & Pricing
1999

Manager, Rates & Cost of Service
1997

Manager, Cost of Service
1995

Supervisor, Cost of Service Studies
1992

Co-ordinator, Regulatory Projects (NEB)
1990

Analyst, Financial Studies
1988

TransCanada PipeLines Limited, Toronto

Co-op Student
1987

Education:	Canadian Investment Manager 1993 Certified Management Accountant 1990 Honours Bachelor of Business Administration (Co-op option), Wilfrid Laurier University, 1988
Memberships:	The Society of Management Accountants of Ontario
Appearances:	**(Ontario Energy Board)** EB-2009-0101 EB-2008-0304 EB-2007-0606 RP-2003-0063 RP-2002-0130 RP-2001-0029 RP-2000-0078 RP-2000-0110 RP-1999-0017 E.B.A. 825 E.B.R.O. 499 E.B.R.O. 493-04/494-06 E.B.R.O. 493/494 E.B.R.O. 486 E.B.R.O. 476-03

Statement of Qualifications
Harold Pankrac

Experience:	**Union Gas Limited**
	Team Leader, Rates and Pricing 1999
	Manager, Rate Design 1997
	Supervisor, Sales and Transportation Rates 1990
	Short Term Planner, Gas Supply Logistics 1987
	Rate Design Analyst 1984
	Dominion Life Assurance Company – Waterloo Individual and Corporate Actuarial 1980
Education:	Bachelor of Arts (Mathematics), McGill University, 1980
Appearances:	**(Ontario Energy Board)**
	E.B.R.O. 499 E.B.A. 825 E.B.R.O. 476-04

Statement of Qualifications
Libby Passmore

Experience:	**Union Gas Limited**
	Manager, Strategic Sales 2011
	Manager, Gas Supply 2008
	Manager, Product and Process Development 2004
	Strategic Manager, Energy Markets 2001
	Manager, Retail Energy Markets 1998
	Manager, Commercial/Industrial Accounts 1995
	Coordinator, Customer Communications 1993
Education:	Honours, Bachelor of Commerce, Queens University
Appearances:	**(Ontario Energy Board)** EB-2008-0106 EB-2007-0725 EB-2005-0551

Statement of Qualifications
Patti Piett

Experience: **Union Gas Limited**

Director, Storage and Transportation Sales
2012

Director, Gas Supply
2008

Manager, Gas Supply
2005

Manager, Integration Planning
2005

Group Manager, Large Commercial/Industrial Accounts
2001

Manager, Retail Services
2000

Project Support, St. Clair Pipelines & Business Services
1997

Manager, Marketing Research
1995

Manager, Marketing Research Planning
1991

Supervisor, Marketing Research
1990

Coordinator, Human Resources Planning
1989

Personnel Supervisor, London
1987

Personnel Supervisor, Hamilton
1987

Employee Relations Representative
1985

Staff Assistant, Northern Region
1984

Education: Masters Business Administration, University of Western, 1990

Honours Business Administration, University of Western, 1984

Appearances: **(Ontario Energy Board)**
EB-2010-0300
EB-2008-0106
EB-2005-0520
EBLO 240
EBRO 476-03
EBRO 486

Statement of Qualifications
Drew Quigley

Experience: **Union Gas Limited**

Manager, Integrated Gas Supply Planning
2005

Risk Specialist, Capacity Management and Utilization
2000

London Reinsurance Group

Manager, Corporate Development
1999

Controller
1994

Accounting Specialist
1992

London Life Insurance Company

Senior Financial Analyst
1989

Canada Trust

Corporate Auditor
1987

National Trust

Branch Auditor
1986

Clarkson Gordon Chartered Accountants (now Ernst & Young)

Senior Staff Accountant
1985

Staff Accountant
1984

Education:	Certified Management Accountant 1991
	Bachelor of Arts (Economics), University of Western 1982
Memberships:	Society of Management Accountants of Ontario
Appearances:	**(Ontario Energy Board)** EB-2007-0724 EB-2005-0551

Statement of Qualifications
Jim Redford

Experience: **Union Gas Limited**

Director, Business Development
2011

Director, Marketing & Storage Development
2009

Director, Marketing & Storage
2008

Project Director, Marketing
2006

Project Manager
2005

Manager, Quality & Performance
2004

Manager, Process Implementation
2002

Project Manager Fit for Purpose Initiatives
2001

St. Clair Pipelines

Manager, Construction
2000

Project Manager Laterals
1998

Union Gas Limited

Senior Pipeline Engineer
1994

Intermediate Pipeline Engineer
1993

Experience (cont'd)	Pipeline Engineer 1990
	Assistant Pipeline Engineer 1989
	Peto MacCallum Ltd. – Toronto 1987
Education:	Professional Engineer 1990
	Bachelor of Applied Science (Geological Engineering) University of Toronto 1987
Memberships:	Association of Professional Engineers of Ontario (A.P.E.O.)
Appearances:	**(Ontario Energy Board)** EB-2005-0551 GH-4-98 GH-2-99 GH-4-99

Statement of Qualifications
David Richards

Experience: **Union Gas Limited**

Manager, Governance and Reporting
2008

Manager, Strategic Development
2005

Product Developer
2000

Coordinator, Storage & Transportation Projects
1995

Coordinator, Storage & Transportation Contracts
1992

Cost Allocation/Rate Design Analyst
1990

Education: Bachelor of Commerce (Honours), University of Windsor
1989

Bachelor of Science (Honours), University of Windsor,
1985

Memberships: Project Management Institute

Project Management Professional (PMP)

Appearances: None

Statement of Qualifications
Chris R. Shorts

Experience: **Union Gas Limited**

Director Gas Supply
2012

Business Unit Liaison
2011

Manager, Product and Process Development
2008

Strategic Manager, Sales Services
2007

Manager, Ontario Power Markets
1999

Commercial Manager, Steel and Power Markets
1997

Manager, Industrial Gas Delivery Services
1994

Administrator, Direct Purchase
1990

Coordinator, Direct Purchase
1988

Regulatory Accounting Analyst
1986

Canadian Imperial Bank of Commerce

Administration Officer
1984

Education: Honours, Bachelor of Commerce, University of Windsor
1984

Appearances: **(Ontario Energy Board)**

EB-2008-0106
EB-2007-0725
EB-2005-0551
EBRO 493/494
EBRO 486
EBRO 476 (DP)

Statement of Qualifications
Robin Stevenson

Experience: **Union Gas Limited**

Team Leader, Product and Services Costing
2011

Team Lead, Gas Management Services
2005

Duke Energy Corporation

Strategic Sourcing Specialist, Global Sourcing and Logistics
2004

Union Gas Limited

Gas Management Services Specialist, Gas Management Services
2002

Business Analyst, Customer Support Services
2001

Pricing Analyst, Rates and Pricing
2001

Education: Masters of Business Administration, University of Windsor
2004

Bachelor of Commerce Honours, Queen's University
2000

Memberships: None

Appearances: None

Statement of Qualifications
Greg Tetreault

Experience:	**Union Gas Limited**
	Manager, Rates and Pricing 2008
	Manager, Gas Management Services 2005
	Team Lead, Gas Management Services 2001
	Nominations Specialist, Gas Management Services 1999
	Business Analyst, Industrial Marketing and Sales 1998
Education:	Honours Bachelor of Commerce, Finance, University of Windsor 1998
	Bachelor of Arts, Geography, University of Windsor 1995
Memberships:	None
Appearances:	**(Ontario Energy Board)** EB-2011-0038 EB-2010-0039 EB-2008-0411 EB-2008-0106

Statement of Qualifications
Paul Trombley

Experience: **Union Gas Limited**

Manager, Capital Reporting
2010

Manager, Financial Reporting & Pensions
2006

Team Lead, Financial Reporting
2005

Senior Analyst, Financial Reporting
2005

Thompsons Limited

Corporate Controller
2004

Assistant Controller
2002

Divisional Controller
2001

KPMG LLP

Staff Accountant
1998

Education: Chartered Accountant – Institute of Chartered Accountants of Ontario
2001

Honours Bachelor of Commerce, Accounting, University of Windsor
1998

Appearances: None

Statement of Qualifications
Sarah Van Der Paelt

Experience: **Union Gas Limited**

Director, Sales Business Markets
2011

Director, Commercial Industrial Sales & Marketing
2008

Director, Energy Conservation
2007

Director, Accounting Services
2005

Manager, Revenue & Gas Accounting
2004

Manager, Financial Forecasts
2004

Manager, Product and Service Development
2002

Manager, Product Development
1999

Administrator, Gas Delivery Products & Services
1997

Supervisor, S&T Nominations
1995

Supervisor, Gas Supply Nominations
1993

Rate Design Analyst
1992

Cost Allocation Analyst
1991

Financial Forecast Analyst
1991

Experience (cont'd)	**The Royal Bank of Canada**
	Assistant Manager, Customer Service 1987
Education:	Certified General Accountant 1998
	Masters of Business Administration, University of Windsor 1991
	Bachelor of Commerce, University of Windsor 1987
Memberships:	The Association of Certified General Accountants
Appearances:	**(Ontario Energy Board)** RP-2003-0063 RP-2002-0130 E.B.R.O. 493-04/494-06

Statement of Qualifications
Linda Vienneau

Experience: **Union Gas Limited**

Manager, Plant Accounting
2008

Administration Manager, Storage & Transmission Operations
2006

Senior Coordinator, Operations Budgets
2004

AIG – American International Company, Ltd. – Bermuda

Accountant – Financial Analyst
2001

Active Burgess Mould & Design – Windsor

Corporate Controller
1998

Renaud & LaMantia, Chartered Accountants – Windsor

Senior Staff Accountant
1994

Education: Chartered Accountant
1996

Bachelor of Mathematics, University of Waterloo
1994

Memberships: Institute of Chartered Accountants of Ontario

Canadian Institute of Chartered Accountants

Appearances: **(Ontario Energy Board)**
EB-2011-0038

Statement of Qualifications
Matt Wood

Experience:	**Union Gas Limited**
	Manager, System Planning 2011
	Manager, STO Process Improvement & Planning 2009
	Maintenance Engineer 2006
	Storage Planning Engineer-in-Training 2004
	Gates Automotive
	Maintenance Engineer-in-Training 2004
Education:	Master of Management Science - University of Waterloo 2010
	Bachelor of Engineering Science - University of Western 2004
Appearances:	None

UNION GAS LIMITED
GLOSSARY

10^3m^3 – One thousand cubic metres, this is the basic metric volumetric unit for gas, in place of Mcf. One thousand cubic metres equals approximately 35.3 Mcf.

20-year declining trend – The 20-year declining trend is a method used to establish the weather normal assumption that is used in the demand forecast for the residential, commercial and light industrial core markets. The 20-year declining trend is a simple linear trend line developed from the most recent 20 years of annual heating degree data. This trend line is then projected forward to provide the expected annual heating degree-days for forecast years.

30- year average – The previous method Union used to establish the weather normal assumption that was used to develop the demand forecast for the residential, commercial and light industrial core markets. The 30-year average is a simple mathematical average of the most recent 30 years of annual heating degree data. This average is then the expected annual heating degree-days for forecast years.

Aid to Construct – A charge collected in advance of construction from new customers who have agreed to fund the shortfall in the economics of a project to serve them.

Alberta Energy Company price point ("AECO") – The price of gas at the Alberta Energy Company storage facility located to the west of Empress.

Alberta Border Reference Price – The Alberta border forward price established in Union's QRAM process.

Alliance/Vector – A pipeline system comprised of the Alliance Pipeline, which runs from Northeastern B.C. to Joliet, Illinois (near Chicago), and the Vector Pipeline which runs from Joliet, Illinois to the interconnect with Union at Dawn.

Authorized Overrun Service ("AOS") – A service that Union, as a firm transportation (FT) shipper on the Alliance Pipeline can access, which allows it to ship on a toll-free basis, up to 16% (on an estimated annual average basis) of its FT capacity. This enables Union to transport gas in excess of its contracted capacity at no additional cost except fuel.

Avoided Costs – The marginal costs that are avoided by not producing and delivering the next unit of energy to the customer. Marginal costs (or avoided costs) include costs related to the energy commodity itself (or its generation) as well as its transmission and distribution.

Bcf – Billion cubic feet

Base Pay – The fixed compensation paid to an employee for performing specific job responsibilities. It is typically paid as a salary or hourly rate.

Basis – The differential between the future or forward price for a given commodity and the cash or spot price for such commodity. It can reflect differences in time periods, product qualities or locations.

Basis Point ("bps") – A unit equal to 1/100th of 1% and is used in denoting the change in a financial instrument. The basis point is commonly used for calculating changes in yield of a fixed-income security, interest rates and equity indexes.

Bundled Service – a service in which the demand for natural gas at a customer delivery point is met by Union using whatever resources/functions or combination of resources/functions (e.g. transportation, storage, daily nominations) are required. Union offers bundled, semi-bundled (e.g. T-1, T-3) and unbundled (e.g. U2, U5, U7) services to its in-franchise customers.

Bridge Year – The year or years between the company's most recently completed actual year and its projected test year.

Bright Compressor Station ("Bright") – Bright is one of two mainline compressor stations (the other is the Lobo Compressor Station) along Union's Dawn-Parkway system. Bright is located west of Kitchener Waterloo. The compression facilities along with the pipeline network are used to move volumes from Dawn to Parkway.

British Thermal Unit ("BTU") – The amount of heat energy necessary to raise the temperature of one pound of water one degree Fahrenheit.

Canadian Standards Association ("CSA") Code – This refers to the CSA standard Z662, Oil and Gas Pipeline Systems. This standard covers the design, construction, operation and maintenance of oil and gas industry pipeline systems.

Canadian Gas Price Reporter ("CGPR") Index – A monthly publication which provides natural gas prices or indices and other information based on transactions at various points and for various time periods as reported to CGPR by the parties entering into transactions during the previous month.

Capital Taxes – The federal capital tax is referred to as the Large Corporation Tax. This tax is calculated by taking a company's taxable capital for tax purposes and multiplying it by the large corporation tax rate for the particular year. The federal government establishes the large corporation tax rate.

The provincial capital tax is referred to as Capital Tax. This tax is calculated by taking a company's estimated taxable capital for tax purposes and multiplying it by the provincial capital tax rate for the particular year. The provincial government establishes the capital tax rate for this calculation.

Compressor – A device used to increase the pressure in the pipeline system.

Construction Work In Process (“CWIP”) – Expenditures incurred in relation to the construction of a capital asset that is not yet ready for use.

Cross-Charge – The cost charged to Union’s non-utility storage operations for the use of utility storage space in excess of utility requirements. This cost is expensed on the non-utility financials and utility O&M expenses are reduced by this amount.

Cubic Foot – The imperial unit of measurement of natural gas volume; the amount of gas required to fill a volume of one cubic foot under stated conditions of temperature, pressure, and water vapour.

Cubic Metre – That volume of gas which at a temperature of 15 degrees Celsius and at an absolute pressure of 101.325 kilopascals occupies one cubic metre.

Customer Supplied Fuel – represents compressor fuel collected from M12 and C1 storage and transportation services customers.

Daily Contract Quantity (“DCQ”) – The maximum amount of natural gas per day that a direct purchaser may deliver to Union’s system under the provisions of a direct purchase contract.

Dawn Compressor Station (“Dawn”) – The location of Union’s main compressor station. Dawn is referred to as a “hub” as it represents the point where Union’s supply, storage and transmission systems meet. A number of other pipeline systems (e.g. TCPL, Vector) are interconnected to Union’s system at Dawn. Dawn is located southeast of Sarnia, Ontario.

Decatherm (“Dth”) – A measurement of heat equivalent to one million BTUs.

Deliverability – The capability of a storage reservoir or pipeline to deliver gas at a given flowing pressure. It is usually expressed in thousands of cubic metres per day (10^3m^3).

Delivered supply – See Spot Gas.

Demand – This is the level of need for natural gas at a specific location. Examples of where this can be found are; the point of end use (a residential, commercial or industrial customer), at the supply point to a community, a takeoff point from a transmission, or at an interconnect with another pipeline system.

Demand Forecast – The demand forecast is a prediction of the total natural gas expected to be consumed in a future period. This could apply to a customer class, rate class or market.

Demand Side Management (“DSM”) – The active promotion of energy-conserving technologies and behaviours among Union's customers.

Design Day Requirements – Design day requirements are the expected demands by a customer at Union's design weather condition. Union plans to have facilities in place to meet these requirements.

Direct purchase ("DP") – A service whereby a customer or their agent arranges for gas supply and/or upstream transmission services directly, and arranges for Union's distribution service to deliver gas to end-user locations.

Discounted Cash Flow ("DCF") analysis – Represents an analysis of the incremental cash inflows and outflows resulting from a project. Cash Flows are discounted using the utility's incremental weighted average after tax cost of capital.

Down Hole Piping (Casing) – Metal pipe lowered into the borehole and cemented into place during natural gas well drilling operations. This piping prevents the sides of the hole from collapsing and the migration of fluids between porous formations.

DSM Consultative – A body composed of representatives from Union, selected intervenors and other stakeholders that provide advice to Union on DSM matters.

Easement – A right held by one person to make specific, limited use of land owned by another person. An easement is granted by the owner of the property for the convenience, or ease, of the person using the property. Common easements include the right to pass across the property, the right to construct and maintain a roadway across the property, the right to construct a pipeline under the land, or a power line over the land. (not sure where this shows up in the rate case?)

Eastern Delivery Area ("EDA") – TCPL's Eastern Delivery Area. Extends from a point on TransCanada's pipeline near Bowmanville, Ontario and from a point on TransCanada's North Bay Shortcut near North Bay, Ontario to a point on TransCanada's pipeline at the International Border near Philipsburg, Quebec and to a point on the pipeline system of Trans Quebec & Maritimes Pipeline Inc. near Quebec City, Quebec.

Eastern Zone Toll – TCPL toll that applies to all points in TCPL's Central Delivery Area, the Southwestern Delivery Area and the Eastern Delivery Area.

EGD – Enbridge Gas Distribution

Empress – The Interconnect between NOVA and TCPL immediately east of the Alberta/Saskatchewan border.

Ex-Franchise – Customers located outside Union's franchise areas.

FT (Firm Transportation) – A firm service, pipeline companies offer for the transportation of gas on their system.

Free Drivers – natural gas consumers that implement energy efficiency measures as a result of reviewing Union's energy efficiency information from a particular DSM program, but do not register as participants in the program once the energy efficiency measure is implemented.

Fuel Gas – Gas used as fuel to operate the compressors that move the gas through the pipeline. Usually expressed as a percentage of volumes transported.

Full Time Equivalent ("FTE") – FTE's are derived by converting part-time roles into full-time equivalents using hours worked and adding the number of full-time roles. The total number of roles (establishment) is derived by adding filled positions (# of employees or headcount) to vacant positions.

GJ (gigajoule) – See Joule. 1 GJ = 10^9 J (refer to conversion table at the end of the glossary).

Gas Distributor – An entity that physically delivers gas to a consumer.

Gas Distributor Consolidated Billing ("DCB") – A method of billing whereby the Gas Distributor issues a single bill to a consumer setting out the charges for gas distribution services and the charges for the gas commodity. This is otherwise referred to as the Agency, Billing and Collection ("ABC") service.

Gas Supply Commodity Rate (North) – This rate reflects the commodity cost of gas and the associated upstream transportation fuel to transport gas to the delivery area in the North in which the gas is consumed.

Gas Supply Transportation Rate (North) – This rate reflects all the costs of upstream (TCPL) transportation, the associated Dawn-Trafalgar transportation and TCPL STS services that are used to provide daily firm service to each delivery area in the North.

Gas Supply Commodity Charge (South) – This rate reflects the commodity cost of gas and the associated upstream transportation fuel to transport gas to the South.

Gas Vendor – An entity who (a) sells or offers to sell gas to a consumer, or (b) acts as the agent or broker for a seller of gas to a consumer, or (c) acts or offers to act as the agent or broker of a consumer in the purchase of gas.

General Service – Non-contract distribution customers served on Union's M1, M2, Rate 01 and Rate 10 rate schedules.

Heating Degree Day ("HDD") – Heating degree-day is the unit of measurement for weather normalization. One heating degree-day (HDD) is a measure of the heating demand for natural gas caused by a one-degree temperature difference relative to Union's temperature benchmark of 18°C. The number of HDDs, on one day, is determined by subtracting the mean daily temperature for the day from the benchmark temperature. For example, if the mean daily temperature is 11°C, then there are 7 HDDs (i.e. 18-11) on that day. If the mean daily temperature is above 18°C, there are no HDDs.

Historical Year – The most recently completed year for which actual data is provided.

Hoop Stress – The stress around the circumference of a pipe (i.e. perpendicular to the pipe length) that results from internal pressure.

Hub – An interchange where multiple pipelines interconnect and form a market center.

Hydrostatic Test – This is a pressure test of the pipeline using water as the medium to confirm its structural integrity.

Interruptible Transportation Service ("IT") – Gas service which is subject to curtailment for either capacity and/or supply reasons, at the option of the Company.

Implementation Guide for Electricity – A term borrowed from the Ontario electricity sector that sets out the detailed guidelines to implement the EBT standards. This term is not referenced in the natural gas EBT standards.

In-Franchise – Customers inside Union's franchise areas.

Independent Market Operator ("IMO") – An independent entity in Ontario charged with operating the wholesale electricity market.

Independent Power Producer ("IPP") – A non-utility power generating entity, that typically sells the power it generates to electric utilities at wholesale prices.

Investment Portfolio – The costs and revenues associated with all new distribution customers who are forecast to attach in a particular test year (including new customers attaching on existing mains). The Investment Portfolio includes a forecast of normalized reinforcement costs.

Joule (J) – The metric unit of energy.

Leave to Construct Application – This is an application to the Ontario Energy Board for approval to construct a hydrocarbon pipeline.

Line Pack – Inventory of gas in a pipeline, or in a gas distribution system.

Load Balancing – The efforts of a utility to meet its bundled customer requirements in the most economic manner on a daily or seasonal basis. It involves balancing the gas supply to meet total demands by using storage and other peak supply sources (e.g. spot gas) curtailment of interruptible demands, and diversions from one delivery point to another.

Load Factor – The ratio of average load to peak load during a specific period of time, expressed as a percent. It indicates the average utilization of a pipeline system relative to total system capacity.

Load Duration Profile/Curve – A curve of loads, plotted in descending order of magnitude, against time intervals for a specified period. The curve indicates the period of time load was above a certain magnitude. Load duration curves are profiles of system demand that can be drawn for specified periods of time (e.g., daily, monthly, yearly). The coordinates may be absolute quantities or percentages.

Loading Factor – The loading factor is the number by which a direct cost is multiplied to arrive at the fully loaded cost. The fully loaded cost is a cost-based price that is the sum of the direct costs (such as employee salaries and other expenditures) incurred in providing the service and the indirect costs (such as payroll benefits, cost of assets used and a return on invested capital) that are related to the direct costs. The fully loaded cost is the amount that would be charged to the service receiver.

Lobo Compressor Station ("Lobo") – Lobo is one of two mainline compressor stations (the other is the Bright Compressor Station) along Union's Dawn Parkway system. Lobo is located west of London. The compression facilities along with the pipeline network are used to move volumes from Dawn to Parkway.

Local Ontario Production – Natural gas production in Ontario, most of which is delivered or produced in Union's franchise area where it is either purchased by Union for sales service customers' consumption or transported to Dawn (on M-13 contracts with the producers) for sale by the producers to others.

Loop – Loop relates to the action of installing a pipeline section parallel to an existing pipeline. The purpose of this additional facility is to increase system capacity, increase pressure or some combination of the two.

Lost Revenue Adjustment Mechanism ("LRAM") – A mechanism that allows Union to recover the revenues lost as a result of reductions in customers' natural gas consumption caused by the influence of Union's DSM programs. These revenues are recorded in a deferral account.

Mcf – Million cubic feet.

m^3 – See Cubic metre (also refer to conversion table at the end of the glossary).

MMbtu – Million British thermal units (refer to conversion table at the end of the glossary).

Main – Pipe used to carry natural gas from one point to another. As contrasted with service gas pipes, mains usually carry natural gas in large volume for general or collective use.

Market Charge – A fixed lump sum charge to be collected from each customer who connects to a specified pipeline project within a predetermined time period. The charge does not have a declining balance over time. Customers who connect in later years pay the same charge as customers who connect in earlier years.

Market Strip (one-year strip) – The average future price of gas over a specified term.

Market Transformation – a program designed to produce market effects that change the structure of a market or the behaviour of market players, and which creates an increase in the adoption of an energy efficient technology, service, or practice.

Measurement Canada – Measurement Canada sets the rules of the marketplace with respect to trade measurement and ensures that they are uniformly implemented and respected through the administration of the Weights and Measures Act and the Electricity and Gas Inspection Act. Measurement Canada's programs and services include evaluating and certifying the accuracy of measuring equipment, investigating complaints received from businesses and consumers who feel they have not received accurate measurement, and certifying measurement standards. They also authorize companies to verify measuring equipment on our behalf and assess the performance of these companies.

Meter – An instrument for measuring and indicating, or recording, the volume of natural gas that has passed through it.

Normalized Average Consumption ("NAC") – NAC is an estimate of the average amount of natural gas a residential, commercial or industrial customer will annually consume, given normal weather conditions. NAC is estimated by determining what the actual average consumption is, and then restating that number to reflect normal weather.

Net Present Value ("NPV") – The sum of the discounted yearly benefits arising from an investment over the life-term of that investment.

Normal Weather – Normal weather is used to calculate normalized average consumption, which is a key element in determining the demand forecast for natural gas. Normal weather is the term used to describe the most likely weather, or more accurately, heating degree-days that can be expected in the long run. Normal weather can be determined by various methods. The current method being used by Union to define normal weather is the 20-year declining trend.

Nominal Pipe Size ("NPS") This is an indication of pipe diameter in inches.

Obligated direct purchase deliveries – Direct purchase customers have an obligation to deliver on a daily basis a certain amount to Union (i.e. their obligated DCQ). Union counts on these deliveries arriving at a specified location in determining the facilities required to meet the design day demand.

Odourant System – Used to add odourant to the natural gas stream to give it a readily detectable odour.

Ontario Landed Reference Price – The Alberta Border Reference Price plus 100% load factor TCPL tolls (to the Eastern Delivery Area) plus compressor fuel established in Union's QRAM process. It is the price that Union charges its sales service customers for the costs of gas supplies and benchmark for recording debits or credits to its gas supply-related deferral accounts.

Panhandle – The Panhandle Eastern Pipeline system that runs from the U.S. mid-continent (Kansas, Texas, Oklahoma) to Michigan and Southwestern Ontario.

Parkway Compressor Station (“Parkway”) - Located at the east end of Union’s Dawn Parkway system. At this location, Union connects with Enbridge and TCPL. Facilities at this site include custody transfer measurement to Enbridge and TCPL. Compression is also located here to facilitate the movement of volumes between Union and TCPL.

Parkway Deliverability – Total planned deliverability at Parkway (including volumes received from TCPL) on design day.

Peak Day – The 24-hour period of greatest total gas sendout.

Peak day requirement – Also referenced as Design Day requirements.

PJ (petajoule) – See Joule. 1 PJ = 10^{15} J.

Profitability Index (“PI”) – The results from the DCF analysis are presented as a ratio of the net present value of revenues to the net present value of costs. This ratio is referred to as the profitability index or PI.

Quarterly Rate Adjustment Mechanism (“QRAM”) – Quarterly Rate Adjustment Mechanism, a streamlined process for obtaining approvals of changes to Union’s commodity rates.

Rate Rider – A temporary surcharge added to base annual rates for the purpose of recovering, within a given period, approved cost variances from forecast costs, in rates.

Regulating Station – A regulating station is a set of equipment which reduces and maintains the pressure in a natural gas transmission or distribution system from a higher level to a lower level.

Regulator – A device designed to reduce and limit the gas pressure at the customer’s meter.

Sales Service – Otherwise referred to as system gas supply. Refers to the sale of the commodity to in-franchise customers by Union.

SENDOUT © – An optimization software developed by NewEnergy Associates which is used by Union for supply/demand modeling as part of its annual gas supply planning process.

Service – The pipe that carries natural gas from the main to a customer meter.

Shared Savings Mechanism ("SSM") – a mechanism that provides utilities the opportunity to earn a financial incentive based on the effectiveness of their DSM programs.

South Portfolio – The mix of upstream transportation capacities that are used to serve customers in the Southern Operations area.

South Portfolio Cost Differential ("SPCD") – The proposed adjustment to the transportation component of the Total Gas Supply Charge for the Southern Operations area to reflect the costs of delivering supplies to sales service customers. It is the difference between the Ontario Landed Reference Price and the South Portfolio costs.

Specified Minimum Yield Strength ("SMYS") – The minimum yield strength prescribed by the specifications or standard to which pipe is manufactured.

Spot gas – Gas supplies that are not underpinned by upstream transportation capacities and which are purchased for delivery at a specific location (e.g. Dawn).

Storage Transportation Service ("STS") – A service offered by TCPL that allows for the movement of gas from a specified delivery area in the North to Parkway (summer "injections") and from Parkway to a specified delivery area (winter "withdrawals") in the North.

Stress Corrosion Cracking ("SCC") – SCC is a particular type of cracking that steel pipelines that operate at higher stress levels, and have the right combination of environmental conditions at the pipe surface, are potentially susceptible to.

System Capacity – This is the measure of the capability of the pipeline system. It is expressed under a set of pressure conditions and shows the system's ability to meet a set of demands specific locations.

TCPL – TransCanada Pipelines Limited

TCPL Turnback – An option given to Direct Purchase customers to return Union's TCPL FT contracted capacity, used to serve their demand, back to Union. Union then de-contracts an equivalent amount of FT capacity with TCPL.

Test Year – The twelve-month period selected as the base for presenting data in a case or hearing before a regulatory agency. It is the period in which projected revenues, costs, expenses and rate base are studied, to evaluate whether the existing rates are adequate to produce a reasonable rate of return.

Therm – A measurement of heat equivalent to 100,000 BTUs.

TFEP – Trafalgar Facilities Expansion Program.

Throughput – The total annual amount of natural gas transported through Union's transmission system.

Toll – A charge levied by a pipeline company.

Total Resource Cost ("TRC") Test **–** A test that measures the net benefits of DSM efforts from a societal perspective (also known as the Societal Cost Test). Under the TRC test, benefits are driven by avoided resource costs, and costs include the equipment and program support associated with delivering that equipment to the marketplace.

Trafalgar – Compressor station located east of the Parkway station. This facility is used to compress volumes to and from TCPL.

Transportation Service ("T-Service") – Service offered by a pipeline company or distributor to transport gas owned by others for a toll.

Trunkline – A pipeline system that runs from the Gulf of Mexico to the border of Indiana and Michigan.

Unabsorbed Demand Charge ("UDC") – Occurs when gas is transported on an upstream transmission pipeline with demand charges included in its toll, at less than 100% load factor.

Unaccounted for Gas ("UFG") – The difference between the total gas available from all sources, and the total gas accounted for as delivery, net interchange, and company use. This difference includes leakage or other actual losses, discrepancies due to meter inaccuracies, variations of temperature and/or pressure, and other variants, particularly due to measurements being made at different times and at different points on the system.

Unbundled Service – A service in which the demand for natural gas at a customer delivery point is met by the level of separate services and functions (e.g. transportation, storage space, storage injection/withdrawal, daily nominations) contracted to be available.

Union North – Refers to the Northern and Eastern Operations Area, or the sections of Union's system that spans north of Toronto to the Manitoba border and east of Toronto to Cornwall.

Union South – Refers to the Southern Operations Area, or the southern section of Union's system that spans as far west as Windsor and as far east as Parkway.

Variable Pay – Compensation that is contingent on discretion, performance, or results achieved. It may be referred to as pay at risk.

Vertical slice – A methodology that was approved by the Board in its RP-1999-0017 Decision to be used by Union to proportionately allocate upstream transportation capacity to its customers in the Southern Operations area who elect to begin direct purchase.

WACC – Weighted average cost of capital.

WACOG – Weighted average cost of gas.

Winter Peaking Service ("WPS") – Winter Peaking Service is one of the non-facility options Union can use to meet its system demands. Volumes will be delivered to Union for a specified maximum number of days at Union's call. This service would be provided by a third party who agrees to deliver the volumes on the days Union nominates them.

Working Capacity – The working capacity is the total volume of gas injected into a storage reservoir in excess of the cushion gas. This is the total maximum volume of gas available for delivery during any injection-withdrawal cycle. EB-2005-0520 Exhibit A1 Tab 15 Page 15 of 15 December, 2005

CONVERSION TABLE

Volume

To convert Mcf to $10^3 m^3$, multiply by 0.02832784.

To convert $10^3 m^3$ to Mcf, multiply by 35.30096.

Energy

To convert MMbtu to GJ, multiply by 1.055056.

To convert GJ to MMbtu, multiply by 0.947817.

UNION GAS LIMITED

SUMMARY OF APPLICATION

INTRODUCTION

Union's last cost of service proceeding established rates effective January 1, 2007 (EB-2005-0520). For the period 2008 to 2012 Union's regulated distribution, transmission and storage rates were determined pursuant to an incentive regulation ("IR") framework agreed to in the EB-2007-0606 Settlement Agreement (January 3, 2008) and as amended in the EB-2009-0101 Settlement Agreement (June 4, 2009). Under the terms of the EB-2007-0606 Settlement Agreement, Union is required to file a full cost of service filing at the end of the IR term for rates effective January 1, 2013.

In Union's view, it is important to have a common understanding of the perspective from which its 2013 rebasing filing was developed, as it will provide context and linkages for the more detailed evidence that follows. This document includes a review of the significant business environmental factors which have and will continue to have an impact on Union, its customers, and its ability to continue to make significant investments in Ontario's energy future and help drive economic prosperity.

2013 REVENUE DEFICIENCY/(SUFFICIENCY)

Relative to 2007 Board-approved levels, Union is projecting a revenue deficiency for 2013 of $71.4 million. The primary drivers of the 2013 revenue deficiency are summarized in Table 1.

Table 1
2013 Proposed vs. 2007 Board-approved
Deficiency / (Sufficiency)

Line. No.	Particulars ($ millions)	Impact		Evidence Reference
		(a)	(b)	(c)
	Revenue:			
1	Contract Market	7		(Exh. C1/Sum Sch 4/Line 23+Line 28)
2	General Service Market	(13)		(Exh. C1/Sum Sch 4/Line 5)
3	S&T[1]	(10)		(Exh. C1/Sum Sch 5/Line13)
4	Other Revenue	1		(Exh. C1/Sum Sch 6/Line 6)
5	Sub Total: Net Revenue	(15)		
6	Delivery-related Gas Costs:	(37)		(Exh. H3/T1/Sch 4)
	O&M:			
7	Compensation	59		(Exh. D1/Sum Sch 2)
8	Contract Services	23		(Exh. D1/Sum Sch 2)
9	DSM Programs [4]	12		(Exh. D1/Sum Sch 2)
10	Outbound Affiliates	(8)		(Exh. D1/Sum Sch 2)
11	Bad Debt	(5)		(Exh. D1/Sum Sch 2)
12	Capitalization	(14)		(Exh. D1/Sum Sch 2)
13	Non-Utility Allocations	(7)		(Exh. D1/Sum Sch 2)
14	Other	7		(Exh. D1/Sum Sch 2)
15	Sub Total: Net O&M [5]	67		(Exh. D1/Sum Sch 2)
16	Rate Base Growth Net of Tax Changes & Debt Costs	20		(Exh. F1/T1/p.3)
17	ROE Formula Change[2]	19		
18	Capital Structure Change	17		(Exh. E1/T1/p.4)
19	Revenue Deficiency	71		(Exh. F1/T1/p.2)

Revenue Deficiency/Sufficiency Adjustment

Line. No.	Particulars	2013	2007
20	Total deficiency [3]	70.6	17
21	Long-term storage subsidy	0.0	(19)
22	Shareholder portion of transactional S&T margin	0.8	2
23	Adjusted deficiency	71.4	-

Note:

(1) Adjusted for the storage premium embedded in 2007 rates.

(2) Calculated using 36% of the 2013 rate base and grossed up using the 2013 proposed income tax rate.

(3) Includes ratepayer and shareholder portions of short-term storage, and transportation and exchange revenues and associated costs.

(4) Approximately $8.0 million has been included in rates over the incentive regulation term via the Y factor.

(5) Includes the impacts of O&M associated productivity initiatives in categories where they were achieved.

The 2013 revenue deficiency includes the impact of increasing Union's return on equity ("ROE") from 8.54% to 9.58%. The pre-tax impact of the ROE increase is $19.0 million. The ROE of 9.58%[1] was calculated using the formula approved by the Board in EB-2009-0084. Final 2013 rates will be based on the Board's approved ROE once the September 2012 actual and forecast bond yields are available. The primary drivers of the 2013 revenue deficiency are described in more detail at Exhibit F1, Tab 1.

2008-2012 INCENTIVE REGULATION EXPERIENCE

As indicated above, Union's regulated distribution, transmission and storage rates were determined under an IR mechanism for 2008 to 2012. Under the IR framework regulated rates were calculated using the price cap formula, defined as PCI = I – X + Z + Y + AU, where PCI is the price cap index, I is the inflation factor, X is the productivity factor, Z represents certain non-routine adjustments, Y represents certain predetermined pass-through items and AU is a volume adjustment reflecting changes in average gas use in the General Service rate classes. Table 2 shows the changes to approved revenues between 2008 and 2012 as a result of the application of the price cap formula.

[1] As per the Board's March 3, 2011 notice that provides the cost of capital parameter updates for 2011 cost of service applications for rates effective May 1, 2011.

Table 2
Changes to Approved Revenues
(2008–2012)

Line No.	Particulars ($ millions)	2008	2009	2010	2011	2012
		(a)	(b)	(c)	(d)	(e)
1	Opening Approved Revenue	955,690	955,690	955,690	955,690	955,690
2	PCI-X factor	1,904	(540)	7,404	(2,095)	(2,947)
3	Storage Premium Adjustment	(544)	4,807	10,158	15,509	15,509
4	Y factors	6,354	(1,168)	4,070	36,887	42,951
5	Z factors	-	(880)	(4,967)	(7,031)	(6,899)
6	Closing Approved Revenue	963,404	957,909	972,355	998,960	1,004,304
7	Approved Revenue Less Y factors	957,050	959,077	968,285	962,073	961,353

Table 2 shows that, over the IR term, rate increases as a result of removing the long-term storage premium from rates were largely offset by rate reductions associated with low inflation relative to the fixed productivity factor of 1.82% and tax rate decreases. Customers have enjoyed the benefits associated with flat delivery rates for the extended five-year period with rates increasing by only 0.6%, net of pass-through items, relative to 2007 Board-approved rates. One of the primary drivers to the 2013 deficiency is the fact that, although revenue increased over the IR term, rate increases as determined by the PCI formula were not sufficient to offset cost increases.

At the same time as ratepayers were enjoying relatively flat rates, they also benefited from earnings sharing over the IR term. Under the terms of the current IR framework, Union shares 50/50 with ratepayers earnings in excess of 200 bps above the ROE, calculated annually using the Board's ROE formula underpinning 2007 Board-approved rates. Earnings in excess of 300 bps above the benchmark ROE are shared 90/10 in favour of ratepayers. Table 3 compares Union's Actual ROE to the Benchmark ROE for the years 2008 to 2012.

Table 3
Actual ROE Compared to Benchmark ROE (2008-2012)

Line No.		2008 (a)	2009 (b)	2010 (c)	2011 (d)	2012 (e)
1	Actual ROE (%)	13.35	11.22	10.91	11.57	8.06
2	Benchmark ROE (%)	8.81	8.47	8.54	8.10	8.10
3	Difference (%)	4.54	2.75	2.37	3.47	(0.4)
4	Sufficiency/(Deficiency) ($ millions)	82.3	51.6	44.1	62.45	(0.8)

The primary drivers of earnings sharing over the IR term were sustainable productivity gains associated with initiatives Union undertook between 2008 and 2011 (Exhibit A2, Tab 5); unsustainable productivity gains revenue associated with the optimization of Union's upstream capacity through the use of TransCanada Pipelines ("TCPL") Firm Transportation Risk Alleviation Mechanism ("FT RAM") credits; declining unaccounted-for-gas ("UFG") volumes; and, favourable weather.

Union is not projecting an earnings sufficiency beyond 2011. First, as indicated above, although rates did increase as a result of the removal of long-term storage premium from rates, these increases were largely offset by rate reductions associated with low inflation relative to the fixed productivity factor of 1.82% and tax rate decreases. Second, the ability to achieve incremental productivity gains beyond 2012 is limited and uncertain. Over the IR term, Union was able to achieve sustainable productivity gains at a relatively low cost. Going forward, productivity gains will be harder to achieve and will require significant investment. Third, a key contributing factor to earnings over the IR term was revenue associated with the optimization of Union's upstream transportation capacity. With the expected elimination of TCPL FT RAM credits in November, 2012, Union's ability to earn revenue from upstream capacity is severely limited (Exhibit C1, Tab 3). Finally, favourable UFG volume variances have contributed significantly to earnings over the IR term. Given the current historic low level of UFG, it is unlikely that UFG will contribute in any significant way to earnings in the future.

FACTORS INFLUENCING UNION'S 2013 REBASING APPLICATION AND NEXT GENERATION INCENTIVE REGULATION

As indicated above, it is Union's view that it is important to identify and describe the significant factors influencing its 2013 rebasing application and its proposals related to the next generation IR. The factors affecting Union's forecast are described under the following headings:

1) Changes in North American Gas Supply Dynamics
    a) Dawn-Parkway Transmission System Impacts
    b) TCPL Maple Constraint

   c) TCPL Mainline Toll Application
   d) Market-Based Storage Prices

2) Factors Influencing In-franchise Demands and Revenues
   a) Energy Prices
   b) Demand Side Management
   c) Weather
   d) Power Generation (Phase-out of Coal-fired Electricity Generation)
   e) Other Factors Affecting Commercial & Industrial Demand

3) Other Factors Influencing the 2013 Rebasing Application
   a) Productivity Gains Over the IR Term
   b) Asset Integrity Programs
   c) Compensation
   d) Pension, Benefits and Post-Retirement Benefits Cost Pressures
   e) Return on Equity and Equity Level

4) 2014 and Beyond (Next Generation IR Mechanism)

1) CHANGES IN NORTH AMERICAN GAS SUPPLY DYNAMICS

Natural gas markets in North America have been substantially transformed in recent years by the decline of traditional supply basins, such as the Western Canadian Sedimentary Basin ("WCSB") and the emergence of unconventional supplies, such as Marcellus shale gas and U.S. Rockies gas. The change in flow patterns has created significant uncertainty for gas flows on Union's Dawn-Parkway transmission system. This uncertainty is expected to continue well beyond the 2013 test year.

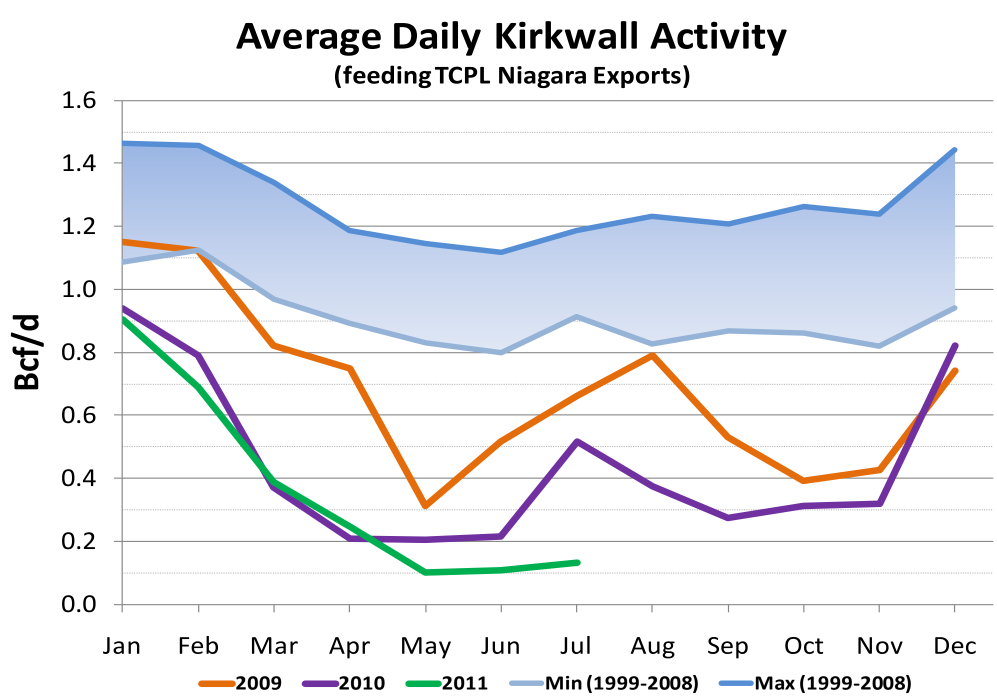
Since 2006, there has been a significant reduction in conventional gas production in the WCSB due to well depletion and the refocusing of production resources on the more economic emerging North American shale gas areas. At the same time that conventional Alberta production has declined, there has been an increase in demand for gas within Alberta by new oil sands development. Although these two factors have been partially offset by emerging shale development in British Columbia, the amount of gas available for export from Alberta on the TCPL mainline has been in steady decline. Natural gas flows on TCPL have declined from approximately 6 Bcf/d to approximately 3 Bcf/d between 2007 and 2011.

The emergence of shale gas production areas such as Marcellus has had a significant impact on North American supply dynamics. Supplies from shale gas plays are displacing WCSB supplies and, as a result, are changing the way gas has been traditionally transported. Further, the overall increase in supply resulting from shale gas development has led to lower and more stable gas prices, significantly impacting storage pricing and demands.

a) Dawn-Parkway Transmission System Impacts

As indicated by Union in the 2010 Natural Gas Market Review ("NGMR") (EB-2010-0199), as a result of the decline in WCSB and the emergence of Marcellus shale supply between 2011 and 2013, revenues from Union's Dawn-Kirkwall transportation service are at risk. As the Marcellus basin continues to develop, the export of natural gas into the U.S. at TCPL's export points (Chippawa and Niagara) has declined. Natural gas that is exported at these two points has traditionally flowed on Union's Dawn-Kirkwall path. As exports decline, the need for parties to hold Dawn-Kirkwall capacity also declines resulting in lost revenue. Figure 1 shows the substantial decline in Dawn-Kirkwall volumes from 1999 to 2011.

Figure 1



Union has already experienced significant turnback of Dawn-Kirkwall capacity by TCPL. At the time of the NGMR, TCPL had already given Union notice (October 31, 2009) for November 1, 2011 non-renewal of 317,000 GJ/d of Dawn-Kirkwall capacity. Union has resold this capacity as Dawn-Parkway service and Dawn-Kirkwall service. On October 31, 2010, TCPL turned back a further 375,000 GJ/d of Dawn-Kirkwall capacity effective November 1, 2012.

On October 31, 2011, TCPL turned back 64,147 GJ/d of Dawn-Parkway capacity and 186,664 GJ/d of Dawn-Kirkwall capacity for November 1, 2013. Two other parties turned back 57,065 GJ/d of Dawn-Parkway capacity. Union's 2013 rebasing forecast includes approximately 350,000 GJ/d of Dawn-Kirkwall and Dawn-Parkway turnback.

The risk of further turnback that exists beyond 2013 is significant. Union estimates the amount of transportation capacity at risk of turnback beyond 2013 to be greater than 800,000 GJ/d.

Table 4 provides the annual turnback starting in 2011 and associated unmitigated revenue impact.

Table 4
Impact of M12 Turnback [1]
Demands as of November 1

Line		Actual 2011 (a)	Forecast 2012 (b)	Forecast 2013 (c)	At Risk 2014-2018 (d)
	Annual Impacts (GJ/d)				
1	Dawn-Kirkwall	(317,000)	(375,188)	(286,198)	(305,137)
2	Dawn-Parkway	-	-	(67,000)	(509,973)
3	Total	(317,000)	(375,188)	(353,198)	(815,110)
	Cumulative Impact (GJ/d)				
4	Dawn-Kirkwall	(317,000)	(692,188)	(978,386)	(1,283,523)
5	Dawn-Parkway	-	-	(67,000)	(576,973)
6	Total	(317,000)	(692,188)	(1,045,386)	(1,860,496) [2]
	Cumulative Revenue Impact ($000's)				
7	Dawn-Kirkwall	(1,258)	(9,009)	(18,086)	(31,374)
8	Dawn-Parkway	-	-	(324)	(16,741)
9	Total	(1,258)	(9,009)	(18,410)	(48,116) [2]

Note:
(1) All contract changes assumed to commence November 1.
(2) Reflects the cumulative totals from 2011 to 2018 and represents the full year impact in 2018 and beyond.

Union has been able to mitigate the Dawn-Kirkwall turnback for 2011 and 2012 by reselling the 2011 turnback as a Dawn-Parkway service and eliminating winter peaking service requirements in 2012. Union does not have a market for any further turnback in 2013 and beyond. Union is working to repurpose the turnback of Dawn-Kirkwall transmission service as a Dawn-Parkway transmission service. Union's ability to repurpose the turnback of Dawn-Kirkwall transmission service is limited by constraints on the TCPL system at Maple.

b) TCPL Maple Constraint

As discussed in EB-2010-0199, transportation capacity is constrained between TCPL's Maple Compressor Station and Union's Dawn-Parkway system at Parkway. The Maple constraint limits the amount of gas that can be transported from Union's Dawn-Parkway system to Eastern Canadian and US markets via TCPL.

TCPL filed a Mainline Eastern Extension application with the National Energy Board ("NEB"). The intent of this application was to increase capacity between Parkway and Maple and to provide bi-directional capability on TCPL at Niagara. The NEB responded that the application was not complete and requested TCPL to file a complete application when ready.

This constraint is a significant concern with long-term implications to Union. The constraint effectively prevents Union from selling Kirkwall-Parkway capacity and excess Dawn-Parkway capacity to customers wishing to source gas in the Marcellus or at Dawn for markets east of Parkway. On March 13, 2012, Union announced a binding open season for the Parkway Extension Project offering more than 500TJ/d of firm transportation service on a proposed new pipeline from a new interconnect near Union's Parkway compressor station to a new interconnect with the TCPL transmission system at or near Maple.

c) TCPL Mainline Toll Application

As indicated above, gas flows on TCPL's mainline have been in steady decline since 2007. As a result, TCPL mainline tolls have doubled since 2007. In response to the significant increase in tolls, TCPL filed an application with the NEB on September 1, 2011 proposing to re-organize their transportation services and change their toll design. TCPL's mainline toll application would set rates for 2012 and 2013.

TCPL's mainline toll application contains a number of toll redesign proposals and financial measures that impact both TCPL long-haul and short-haul tolls. Union's primary concern with TCPL's proposed tolls, as it relates to the Dawn-Parkway transmission system, is with the sustainability of TCPL short-haul tolls. TCPL short-haul tolls must remain competitive in relation to services offered on other transportation paths. Union is concerned that TCPL's rate proposal does not result in a long-term, sustainable solution that maintains the competitiveness of short-haul tolls. If short-haul tolls increase over time, these services may become uncompetitive and cause current short-haul shippers to seek transportation options that bypass Union's Dawn-Parkway transmission system. Only by maintaining competitive short-haul tolls (and the removal of the capacity constraint between Parkway and Maple) will shippers consider contracting for Dawn-Parkway services.

TCPL has also proposed to increase tolls for interruptible (“IT”) and short-term firm transportation services (“STFT”) and to eliminate the FT RAM. The increase of both the IT and STFT services is intended to extract more revenue from discretionary shippers as well as to attract more shippers to firm service. Eliminating FT RAM is also intended to encourage more shippers to contract firm services or increase their use of the more expensive discretionary services.

At this time, Union generally supports these services and pricing changes intended to increase mainline revenue from transactional services and help preserve lower long-haul and short-haul rates for firm transport service including the elimination of the FT RAM. Union notes, however, that the elimination of TCPL’s FT RAM severely limits Union’s ability to sell exchanges and other upstream transportation services. As indicated above, one of the major contributors to earnings sharing over the IR term was Union’s ability to successfully optimize its upstream capacity.

d) Market-Based Storage Prices

As a result of the significant growth in North American natural gas supplies attributable to shale gas production, natural gas prices are relatively low and stable when compared to historical levels. Price stability, or lack of price volatility, negatively impacts market-based storage prices because storage prices are primarily based on the difference in price between summer and winter seasons. Flat prices between the summer and winter seasons means there is little value in customers purchasing storage contracts from Union.

As a result, storage prices have declined steadily and are forecasted to remain low in the foreseeable future. This impacts the revenues related to the sale of short-term storage services associated with regulated storage space in excess of in-franchise storage space requirements. To illustrate, in 2011 10.1 PJ of short-term peak storage space sold at an average price of $0.71 Cdn/GJ. This compares to a price of $0.85 Cdn/GJ included in 2007 Board-approved rates.

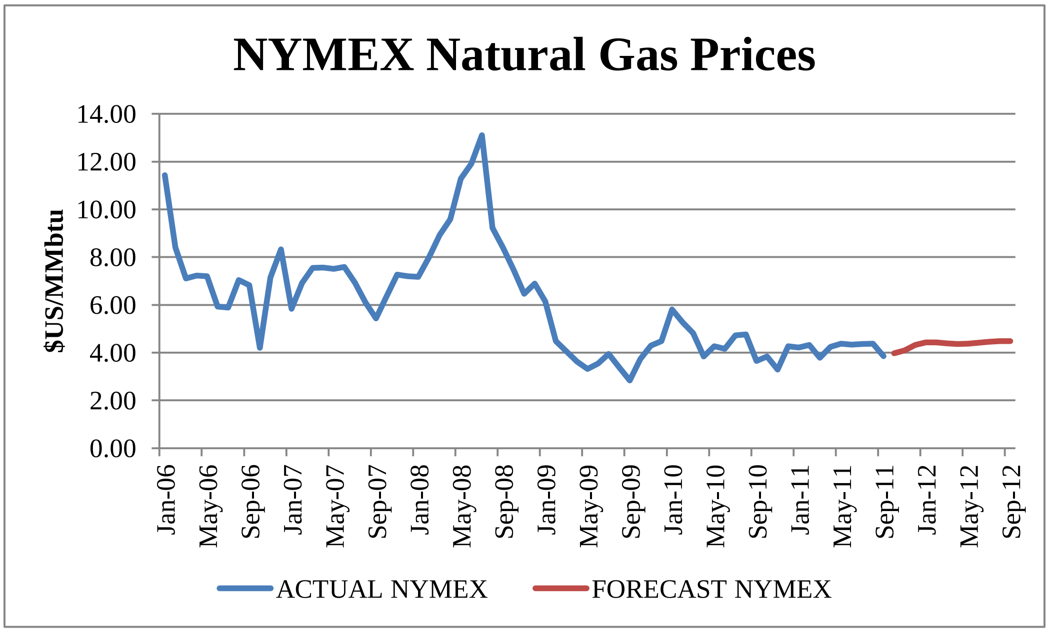
Union is projecting short-term peak storage revenue of $9.0 million in 2013. This compares to $13.9 million in current approved rates.

2) FACTORS INFLUENCING IN-FRANCHISE DEMANDS AND REVENUES

a) Energy Prices

Energy costs impact Union's residential, commercial, and industrial customers as well as Union's own operating costs. On a quarterly basis, Union uses a 21-day average of the twelve month NYMEX strip to establish its natural gas commodity price at the Alberta border as part of the Board-approved Quarterly Rate Adjustment Mechanism ("QRAM") process. As a result of the rapid growth in North American natural gas supplies, natural gas commodity prices have decreased significantly since Union's last cost of service proceeding. Figure 2, shows the change in the actual NYMEX natural gas prices from January 1, 2006 to September 1, 2011.

Figure 2



Low energy prices have a positive impact on consumers and economic growth. Lower costs for consumers are expected to promote economic growth as consumer spending increases. Any consumer led business cycle improvement will positively impact the Ontario economy leading to higher housing starts, greater conversion from other fuels, and increased industrial output.

Low energy costs also have a positive impact on Union's cash flows and operating costs. The impact includes but is not limited to: bad debt expense; gas used to heat Union's buildings; fuel gas used in compressor stations; financial charges in relation to the financing and carrying costs of lower-value natural gas inventory; and, the value of UFG.

b) Demand Side Management

The delivery of Demand Side Management ("DSM") programs by natural gas utilities continues to be an important part of Ontario's overall conservation initiatives. On June 30, 2011, the Board issued the Final DSM Guidelines for Natural Gas Utilities (the "Guidelines"). The Guidelines provided a framework for the 2012-2014 DSM Plans of Union and Enbridge Gas Distribution.

Under the Guidelines, Union proposed to increase its 2012 DSM budget to $30.954 million, an increase of $3.599 million over the approved 2011 DSM budget of $27.355 million. On February 21, 2012, the Board approved a Settlement Agreement for Union's 2012-2014 DSM plan.

For 2013, the DSM budget will be equal to the 2012 DSM budget plus inflation. For 2013, Union is projecting a DSM budget of $31.842 million. The primary cause of the increase in Union's DSM budget is an increased focus on Low-income DSM programming.

c) Weather

Union is proposing to change its weather normalization method for 2013 to a 20-year declining trend weather normalization method. This change will more accurately reflect the weather experience in Union's franchise area.

The current weather normalization method was approved by the Board in its RP-2003-0063 Decision. In its Decision, the Board approved a 70/30 blend of the 30-year simple average and 20-year declining trend method with an additional 5% weighting of the 20-year declining trend in each subsequent years until a 50/50 blend is achieved. In EB-2005-0250, Union did not propose to change its weather normalization method but proposed to update the blending proportion for the year 2007 weather normal to 55% of the 30-year average and 45% of the declining trend estimate. This proposal was agreed to in the EB-2005-0520 Settlement Agreement.

Union selected the 20-year declining trend weather normalization method after researching climate issues and evaluating other weather normalization methods. The 55/45 blend, which has been used previously to set rates, overestimates the heating demand of customers by approximately 2.9% in a typical year. Changing the weather normalization method to a 20-year trend would reduce the number of Heating Degree Days (the difference between mean daily temperatures and 18 ^{0}C) and as a result would reduce forecast throughput and revenue. Moving to the 20-year declining trend weather normalization method also means that Union will not incur more upstream transportation and balancing costs than are actually required. Union continues to experience weather that has a significant warming trend which is not included in the current method. This warming trend has, therefore, not yet been fully recognized in the rates of Union's temperature-sensitive customers.

d) Power Generation (Phase-out of Coal Electricity Generation)

Growth in the gas-fired power generation segment has been driven by the Ontario government's 'off-coal' policy. It is also the only area of significant growth potential in the contract market. Three gas-fired generation facilities have been constructed in Union's franchise area under the Clean Energy Supply ("CES") initiative including:

i) St. Clair Generating Station
ii) East Windsor Cogeneration Center
iii) Halton Hills Generating Station

These projects have supported the supply mix change from coal to other generation sources, including gas-fired generation. Union has invested approximately $41.0 million to bring gas infrastructure to these facilities. In addition, Union is providing high deliverability storage services to these customers. These services were developed specifically to meet the needs of gas-fired generators.

Potential future growth in gas-fired power generation is outlined in the provincial government's Long Term Energy Plan and the Ontario Power Authority's 'IPSP Planning and Consultation Overview'. These plans identify four gas-fired generation projects in

Union's franchise area. They are: the conversion of coal-fired facilities at Thunder Bay, Nanticoke, and Lambton to natural gas; and, a peaking facility in the Waterloo-Cambridge area to provide transmission support. A Ministerial Directive has been issued for the conversion of the Thunder Bay generating station from coal to natural gas. The expected in-service date for the Thunder Bay generating station is November of 2012.

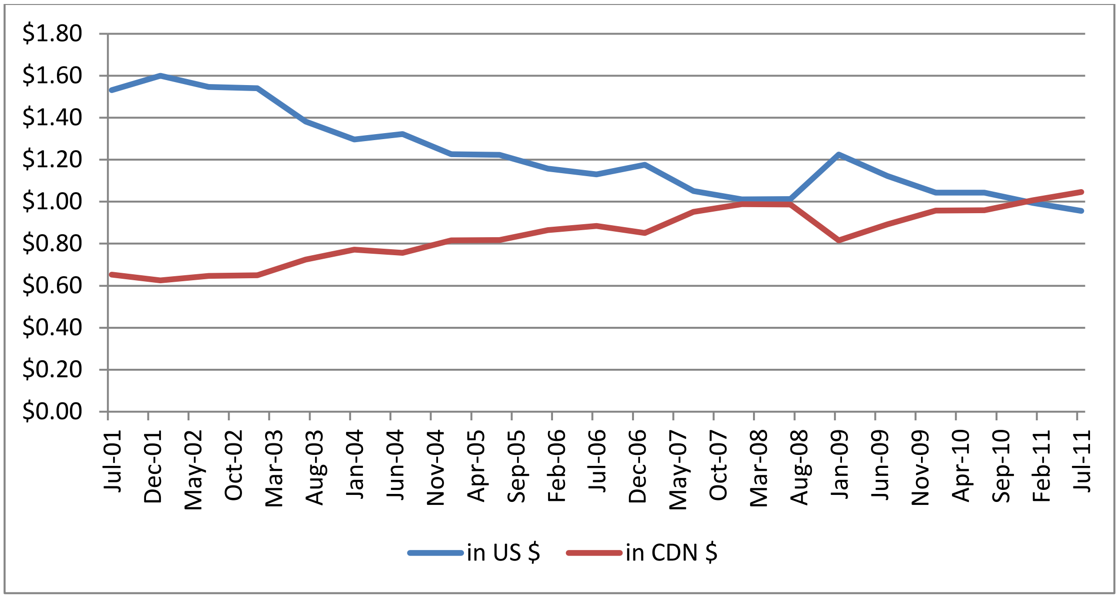
Union is currently supporting Ontario Power Generation Ltd., ("OPG") in the project assessment process for the Nanticoke and Lambton conversion projects. Neither of these projects nor the Waterloo-Cambridge peaking facility have received the required approval to proceed. Therefore, neither the revenue nor the associated capital required to serve these facilities have been built into the forecast, and would be outside the forecast test year period in any event.

e) Other Factors Affecting Commercial and Industrial Demand

i) Foreign Exchange and Manufacturing Competitiveness

Figure 3 shows how foreign exchange rates have changed over the past 10 years.

Figure 3
Canadian-US Exchange Rate



(Source: Bank of Canada)

As shown in Figure 3, the Canadian dollar remained weak in the early 2000's but has been increasing in value since 2009. The dollar recently hit a four year high relative to the U.S. dollar in July, 2011. A strong Canadian dollar has a negative impact on the competitiveness of Ontario's industrial production, as a higher Canadian dollar makes products produced in Canada less attractive to the U.S. market. As exports drop, there is a corresponding reduction in industrial production and natural gas demand.

The July 2011 Monetary Policy Report released by the Bank of Canada indicates the high Canadian dollar is having a negative impact on Canadian business. Nearly half of the firms included in the Business Survey Outlook reported adverse impacts on their business. This view was most common among manufacturers that focus on the U.S. as their main export market. Overall, the summer 2011 Business Outlook Survey suggests that the strong Canadian dollar, together with expectations of continuing softness in U.S. demand and robust competition, are expected to constrain sales prospects over the next 12 months.

In summary, the escalating value of the Canadian dollar is expected to continue to negatively affect the competitiveness of the Canadian manufacturing sector and as a result impair natural gas throughput and revenues.

ii) Business Cycles

The North American economy is slow and still recovering from the most recent economic recession which lasted from the fourth quarter of 2008 to the second quarter of 2009. The Canadian economy is expected to continue to grow in the near future but at a modest pace. The Bank of Canada's July 2011 Monetary Policy Report projects GDP to grow by 2.8% in 2011, 2.6% in 2012 and 2.1% in 2013. While GDP has recovered to pre-recession levels, business investments and exports have not fully recovered. Net exports are also expected to show a modest improvement. Household expenditures are expected to increase moderately as consumers are likely to spend more prudently as result of the economic recession.

The U.S. economy has a significant impact on Canadian business. The U.S economy is recovering but at a slower pace than expected. The level of U.S. public debt is disconcerting and net exports from Canada to the U.S remain weak, reflecting modest U.S. demand and ongoing competitiveness challenges.

Any economic slowdown leads to less industrial output, a reduction in industrial capital investment and lower consumer spending. The recovery of the North American economy has not been reflected in Union's revenue forecast. In conclusion, a further economic slowdown would generate outcomes that result in a reduction in both Union's throughput and revenue that have not been reflected in Union's 2013 forecast.

3) OTHER FACTORS INFLUENCING TO 2013 REBASING APPLICATION

a) Productivity Gains Over the IR term

During the IR term, Union undertook a number of initiatives to drive out productivity gains. Productivity gains can either be achieved through measures that reduce costs or increase revenue. Table 5 summarizes the total cost savings and incremental revenues associated with productivity initiatives over the IR term. A description of Union's productivity initiatives appears at Exhibit A2, Tab 5.

Table 5
Total Productivty Cost Savings and Incremental Revenue Generation

Line No.	Category ($ millions)	2008	2009	2010	2011
		(a)	(b)	(c)	(d)
1	O&M	2.8	12.5	16.0	15.5
2	Capital	0.1	1.9	9.7	10.8
3	Revenue	5.4	14.9	16.1	26.1
4	Total	8.3	29.3	41.8	52.4

Productivity gains are either sustainable or unsustainable. Union's 2013 O&M forecast includes $22.5 million of sustainable productivity gains ($15.9 million plus projected productivity gains of $6.6 million for 2012 and 2013 (Exhibit D1, Tab 2)).

The revenue-related productivity gains, however, are not sustainable. These revenues relate to the optimization of upstream TCPL capacity through the use of FT RAM credits and of Union's Dawn-Parkway transmission system. As indicated above, TCPL is proposing to eliminate the FT RAM program as of November, 2012. With respect to Union's Dawn-Parkway transmission system, Union is not projecting optimization revenue as a result of excess Dawn-Parkway capacity due to turnback.

Union's ability to drive out additional future productivity gains is becoming increasingly difficult and expensive. When combined with rising costs associated with providing safe and reliable service to its customers at the same time volumes and revenues are in decline, a reduced ability to achieve productivity gains leads to an increase in rates. This is the case in 2013.

b) Asset Integrity Programs

The safety and reliability of its pipeline systems continues to be of paramount importance to Union. As technology and practices have evolved, Union has applied greater levels of sophistication to manage the integrity of its storage, transmission and distribution systems. As detailed at Exhibit B1, Tab 6, Union has formal Asset Integrity Management ("AIM") programs in place to manage the increasing scope of its integrity requirements. These programs include i) transmission (pipelines operating at 30% Specified Minimum Yield Strength ("SMYS") or greater; ii) distribution (pipelines operating at below 30% SMYS); iii) storage down-hole piping; and, iv) stations. These AIM programs have been successful in finding and fixing problems on Union's pipeline system before they have been able to materialize into more serious circumstances. Union's approach provides a reasonable balance between adding incremental funding and activities and refining the existing practices through continuous improvement that will ensure the safety and reliability of the overall system. Union's 2013 integrity forecast includes an incremental $6.45 million in capital and $6.16 million in O&M costs compared to levels filed in EB-2005-0520. The implementation of Union's cross-bore management program is included in the 2013 forecast.

c) Compensation

The goal of Union's compensation strategy is to attract, motivate and retain high calibre employees to ensure the Company's success. To help meet this goal, Union offers employees a total cash compensation package that consists of a fixed component (base salary – salaries and wages) and a variable, at risk pay component (Short-Term Incentive Plan – "STIP"). A small number of key leadership employees also have a long-term variable pay component ("LTIP") as part of their total compensation. Each of these compensation components is critical to the success of Union's total compensation package in the competition for talent and the retention of a high performing workforce. Union's total cash compensation strategy is detailed at Exhibit D1, Tab 3.

Compensation levels are based on market conditions to ensure Union's ability to compete for required talent and to retain valued employees. Union's compensation philosophy continues to target total cash and total direct compensation levels to the 50th percentile in the marketplace at target variable pay levels. To validate the competitiveness of its compensation levels, Union compares its compensation levels to a cross-section of national companies of similar revenue size; including energy utilities as well as organizations with operations in Ontario. This compensation philosophy and approach to competitive market analysis has been supported by Union since 2001.

At stated at Exhibit D1, Tab 2, Union's overall Human Resources costs have increased by approximately $41.6 million between 2007 Board-approved costs and the 2013 test year forecast. This increase is driven primarily by salary and wage increases.

d) Pension, Benefits and Post-retirement Benefits Cost Pressures

Similar to its compensation strategy, Union provides a comprehensive pension and benefits program that is essential to attract, motivate and retain qualified employees. Union provides a common platform of pensions and benefits to all employees, both unionized and non-unionized.

The total expense for pension and benefits is forecast to increase from the 2007 Board-approved level of $55.6 million to $81.1 million. The main drivers for the increase are poor capital market returns as a result of the 2008/2009 financial crisis, changes in mortality tables to reflect improved retiree life expectancies, and low yields on long-term Government of Canada and corporate bonds. Union continues to refine and improve its pension and benefits administrative process in order to deliver its offerings in the most efficient and cost effective manner.

e) Return on Equity and Equity Level

As part of this application, Union is proposing to include in rates the impact associated with moving to the Board's revised formula for calculating Return on Equity ("ROE").

For the purposes of Union's 2013 application and evidence, the assumed ROE is 9.58% (May 1, 2011 Consensus). The pre-tax impact on the 2013 deficiency related to an ROE of 9.58% is approximately $19.0 million. Final rates will incorporate the ROE calculated using the September 30, 2012 Consensus.

Union is also proposing to increase its common equity component to 40%. Union's current Board-approved capital structure is based on 36% common equity. This increase in common equity will provide a capital structure that is comparable to the capital structures of other regulated utilities in Ontario and North America and with whom Union competes in the capital markets. Union's capital structure proposals are supported by the expert testimony of Mr. Steven Fetter and Mr. James Vander Weide filed at Exhibit E2 and F2, respectively.

4) 2014 AND BEYOND (NEXT GENERATION IR MECHANISM)

Union will not be proposing the next generation IR mechanism as part of this proceeding. Rather, Union will bring forward a separate application to establish the mechanism for setting rates for 2014 and beyond after the Board renders its decision on this application. Union is taking this approach because of the significant uncertainly it faces with respect to changing North American supply dynamics. It is Union's view that it will be better able to assess its future risks and opportunities, and therefore better able to propose it's next IR mechanism, once 2013 rates are known and some of the factors impacting gas flows on Union's Dawn-Parkway transmission system are better understood.

Union anticipates that it will bring forward an application for its next IR mechanism late in 2012 or early 2013, for implementation effective January 1, 2014.

UNION GAS LIMITED
Revenue Deficiency/Sufficiency Sensitivities
For the year ending December 31, 2013

Line No.	Particulars ($millions)		Deficiency/ (Sufficiency)	
1	Inflation - 1% increase in O&M		3.2	
	100 Basis point increase in Long Canada Bond rate			
2	ROE (1)	10.0		
3	Long term debt (2)	1.3		
4	Pension & other post retirement expenses	(10.6)	0.7	/u
	WACOG - 10% increase			
5	Bad debt expense	0.4		
6	Compressor fuel	2.9		
7	Company use fuel	0.2		
8	UFG	1.4		/u
9	Gas inventory carrying costs	0.9		
10	Customer supplied fuel	(3.0)	2.8	/u
11	Customer attachments - 5,000 additional attachments in 2013		(0.2)	
12	$10 million increase in rate base (no revenue impact)		0.9	
13	1% increase in common equity ratio		4.3	
	Increase NAC by 1%			
14	Residential M1		(0.9)	
15	Residential 01		(0.5)	
16	Increase HDD by 1%		(1.8)	
17	Increase Contract Forecast by 25 x 10^6 m^3		(0.1)	

Notes:
(1) Assumes 100 BP change in Long Canada has a 50 BP impact on ROE based on the formulaic methodologies documented in the *Report of the Board on the Cost of Capiatal for Ontario's Regulated Utilities* , issued December 11, 2009. Assumes 40% common equity capital structure
(2) Full year impact on 2013 long term debt interest expense from $125 million issued in 2012.

UNION GAS LIMITED

CUSTOMER IMPACTS

Union has proposed changes to its delivery rates which, if approved by the Board, will result in approximately a $19 (2.6%) increase on a typical residential customer's annual bill in Union South. In Union North (Northern Zone), the proposed delivery rate changes will result in approximately a $70 (8.3%) increase on a typical residential customer's annual bill. In Union North (Eastern Zone), the proposed delivery rate changes will result in approximately a $76 (8.7%) increase on a typical residential customer's annual bill. The rate changes will take effect on January 1, 2013.

Further detail regarding typical customer impact by customer class can be found at Exhibit H3.

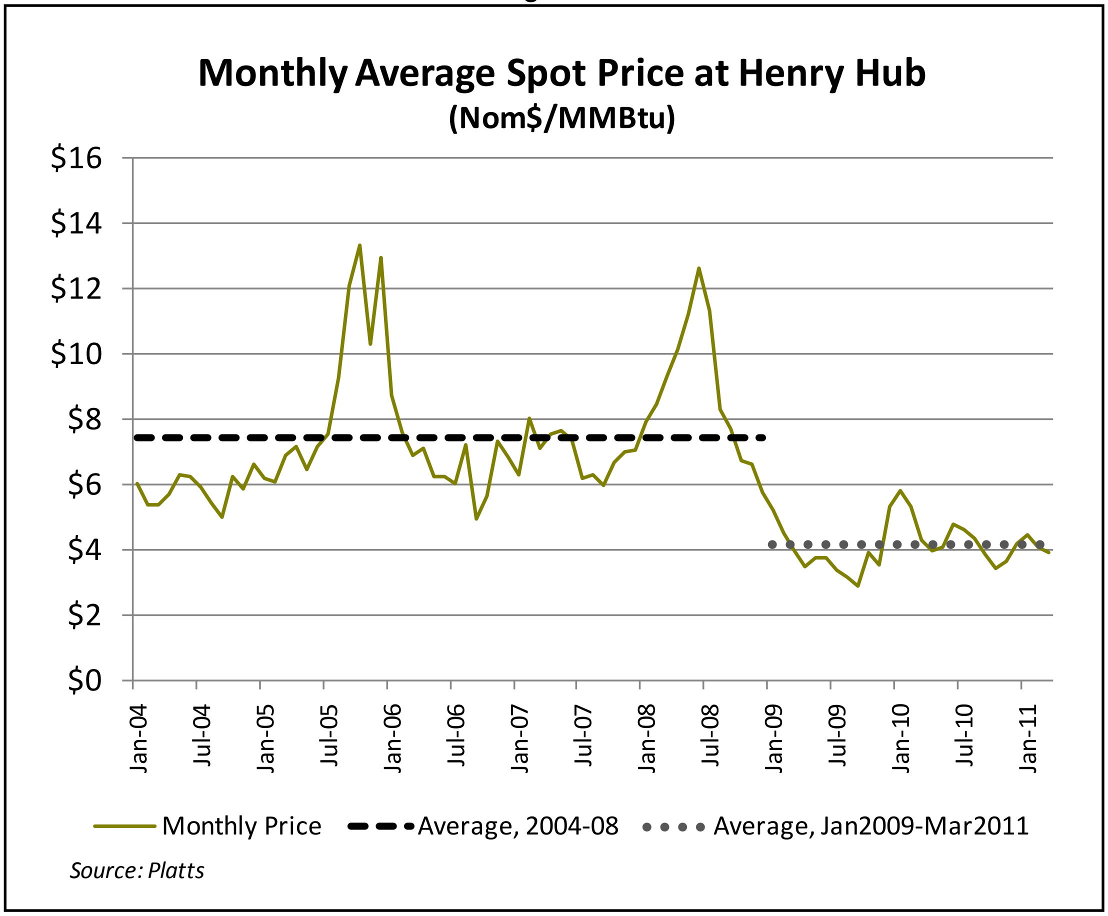
Natural Gas Market Conditions and Impact on Union Gas Limited

Prepared by Bruce B. Henning
ICF International

Executive Summary

Natural gas markets in North America have been substantially transformed in recent years by new exploration and development technologies for unconventional gas. In less than five years, the development of gas from shale formations and other unconventional sources have contributed to a significant moderation in natural gas commodity prices. Between 2004 and 2008, natural gas commodity prices averaged more than $7.50 at Henry Hub, Louisiana. Since 2009, natural gas commodity prices have averaged less than $4.50 at Henry Hub, Louisiana. Moreover, the development of new sources of gas supply has led to a more favorable outlook for future commodity prices from the perspectives of gas consumers.

Figure 1

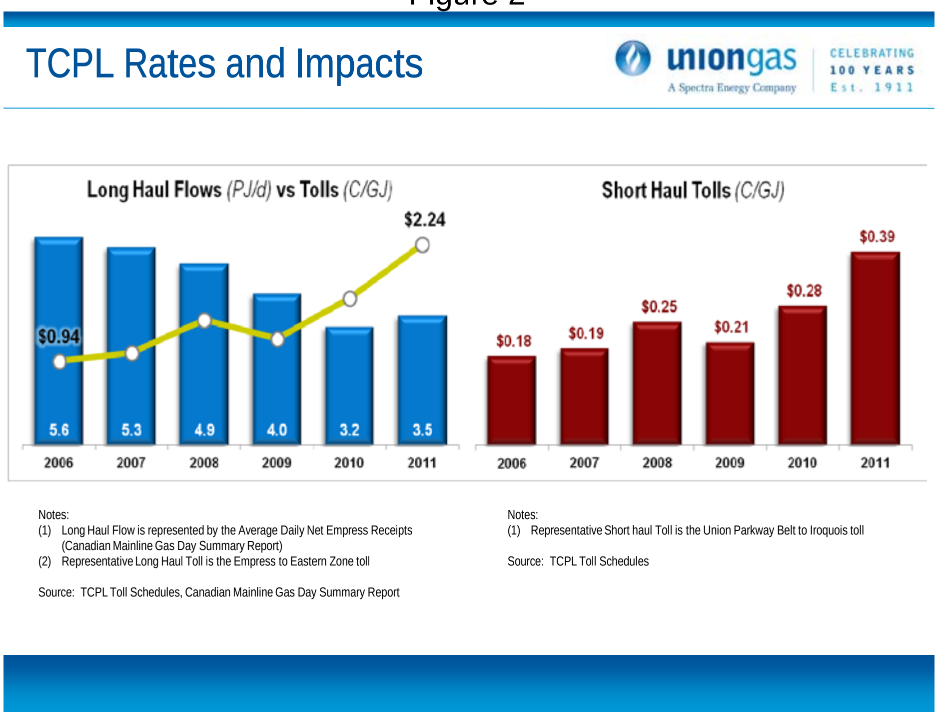


In August 2010, ICF prepared a report entitled, "2010 Natural Gas Market Review (2010 Report)." That report, commissioned by the Ontario Energy Board, discussed the trends and forces shaping the gas market. During the following year, the trend toward increased shale gas production has accelerated at a faster pace than anticipated, despite the "sluggish" economic recovery and modest gas demand growth.

The trends and forces identified in the 2010 Report and revisited here are quite positive for gas consumers in Ontario, in terms of North American gas commodity prices. However, the rapid nature of market changes and uncertainty regarding the economic recovery and natural gas demand are creating a challenging environment for Union Gas Limited ("Union") and downstream shippers that contract for service on Union Gas facilities. Changing throughput patterns and volumes create significant swings in operating conditions, expected revenues, and regulated transportation rates. As a result, shippers face changing economics for the acquisition of gas supply that will precipitate changes in their portfolio of gas transportation and storage assets under contract.

Compounding uncertainties is the status of the process to determine the tolls on the TransCanada Pipeline System (TCPL). As identified in the 2010 Report, throughput on the TCPL Mainline from the Western Canadian Sedimentary Basin (WCSB) to Ontario and points east have declined markedly just as new options for gas supply have emerged. The decline in throughput has resulted in increases in both the long-haul and short-haul tolls on TCPL. With these increases, TCPL service has become less competitive with other options. Gas shippers able to utilize other options have sought to limit exposure to TCPL rate risk accordingly.

Figure 2



Source: Union Gas

Over approximately the last two years, TCPL and shippers have participated in an intensive effort to develop acceptable tolls that address the competitive threats posed to TCPL service. Despite these efforts, a long-term settlement has yet to emerge. TCPL filed a proposal on September 1, 2011 with Canada's National Energy Board (NEB) to respond to changing North American market conditions and impact on the TCPL Mainline. At this time, it is impossible to fully ascertain the proceeding's conclusions with regard to final toll level, and it is unlikely that a permanent resolution will be reached quickly. Indeed, uncertainty associated with TCPL toll levels through 2018 (even after tolls for 2012 and 2013 are determined) is likely to persist.

With these toll increases, both in-franchise and ex-franchise shippers that secure and/or balance their gas supply at Dawn, are considering alternative routes to secure reliable gas supply in a “best-practice” manner. Supply options include:

- Contracting for gas supply from the Marcellus Shale formation and obtaining transportation back to Ontario. Traditionally, these transactions are considered “back-haul” or exchange transactions, but pipelines are proposing to construct and/or modify facilities to allow for firm transportation service.
- Contracting for gas supplies in Chicago and Michigan, and securing firm transportation to Ontario and onto the Union system along traditional transport routes.
- Contracting for gas supply from the U.S. Rocky Mountains through the Rockies Express Pipeline (REX) and eventually to Dawn through connecting pipelines.
- Contracting for conventional or shale gas supply in Texas, Oklahoma and Arkansas, as well as traditional gas production in the Gulf of Mexico and other onshore production areas.
- Continuing to contract for gas from the WCSB with transportation on TCPL.

With these evolving supply options, ex-franchise shippers that currently contract for service from Dawn are considering their options. Certainly they are exploring the new and increasingly abundant supply in the Marcellus region and how they might directly access this supply. To the extent that these shippers do access Marcellus gas directly, they may de-contract on capacity on other paths including Union facilities from Dawn.

Finally, the soft economy and increasing gas production have had an impact on the economics and market value of natural gas storage. Current forward markets reflect only small values for the spread between winter gas commodity prices and prices for the storage injection season. These “seasonal price spreads” form the primary component of the “intrinsic value” of storage. At the same time, natural gas commodity prices have “decoupled” from volatile oil prices and have not exhibited the volatility that contributes to the extrinsic value of storage. In light of these factors and the development of new storage capacity available, market prices for storage have softened substantially over the last two years, a trend that is likely to continue for several years.

Conclusions

There are a number of factors that create significant uncertainty regarding the throughput and utilization of Union Gas facilities through 2018. The combination of an unclear economic outlook, uncertainty regarding TCPL tolls, a relatively soft market for storage, and considerable uncertainty with regard to re-contracting transportation by Ex Franchise shippers together present challenges to Union and the Board.

As increasing volumes of Marcellus gas and other sources of unconventional gas continue to be made available to the market, shippers are likely to adjust contract portfolios to access these supplies. The changing flow patterns are already apparent. With these changing patterns, it is highly likely that shippers will continue to make adjustments in transportation contract portfolios as current contract obligations expire. For Union Gas transportation services, this pattern of re-contracting may be problematic. Existing contracts for firm service across the Union system held by shippers serving markets in Ontario, Quebec, and the U.S. Northeast are “at risk” upon expiration of current contracts.

Introduction and Scope of Engagement

On August 20, 2010, ICF[1] delivered a report entitled, “2010 Natural Gas Market Review (2010 Report),” commissioned by the Board to initiate “a stakeholder process that will review and examine changes in the North American natural gas market to better understand the implications for Ontario’s market.” This White Paper, commissioned by Union Gas Limited (Union Gas):

- Reviews the 2010 Report in the context of the gas market developments and market behavior over 2010.
- Evaluates the degree and pace of market trends identified in the 2010 Report.
- Identifies new developments in the North American gas market.

[1] The report was commissioned by the Ontario Energy Board under a contract with ICF Resources, LLC, a subsidiary of ICF International.

The objective for this review and update was to provide a market context appropriate for considering the value and growth of (or risks to) Union's transmission assets when Union rebases its rates in 2013 and during the subsequent Incentive Regulation period. The trends and market forces presented in the 2010 Report and confirmed in this update have significant implications on the likely utilization of Union Gas assets and uncertainly surrounding any utilization projections.

Overview of the 2010 Report

In the report prepared for the 2010 process, ICF identified a number of important trends influencing the market and projected to have important implications for all North American gas consumers, including those in Ontario. The 2010 Report identified a fundamental shift in the supply and demand balance. Since the onset of the recession, gas demand has shrunk and gas prices have softened. Compounding this, a combination of modest growth potential and large investments in gas supply development have together led to the current environment of historically low natural gas prices.

The development of unconventional gas supplies – particularly shale gas – was identified as the principal driver for this gas price decline. The 2010 Report concluded that the North American gas market was in the early stages of a transformation that would shape gas markets for years to come. The report also identified the correlation between the growth in unconventional gas supplies in the Marcellus and other locations and the continued decline in production from traditional resources, including the Western Canadian Sedimentary Basin (WCSB). These concomitant factors are likely to change the nature of gas supply management for market participants in Ontario.

Market Developments During 2011

The trends and forces shaping the market that were identified in the 2010 Report have since progressed. Indeed, most shifts discussed have become more prominent.

ICF's shale gas resource estimate has increased. ICF have revised the resource estimates shown in Exhibit 32 of the 2010 Report, adding more than 268 trillion cubic feet (TCF), or 14.1 percent. The revised estimates are presented in Figure 3.

Figure 3
U.S. and Canadian Natural Gas Resource Base
(Tcf of Economically Recoverable Resource, Assuming Current E&P Technologies)

	Proven Reserves	Unproved Plus Discovered Undeveloped	Total Remaining Resource	Shale Resource[1]
Alaska	7.7	153.6	161.3	0.0
West Coast Onshore	2.3	24.6	27.0	0.3
Rockies & Great Basin	66.7	388.3	454.9	37.9
West Texas	27.6	47.7	75.3	17.5
Gulf Coast Onshore	70.1	684.7	754.8	476.9
Mid-continent	37.0	205.0	241.9	133.9
Eastern Interior[2,3]	18.6	1053.7	1072.3	986.1
Gulf of Mexico	14.0	238.6	252.5	0.0
U.S. Atlantic Offshore	0.0	32.8	32.8	0.0
U.S. Pacific Offshore	0.8	31.7	32.5	0.0
WCSB	60.4	664.0	724.4	508.8
Arctic Canada	0.4	45.0	45.4	0.0
Eastern Canada Onshore	0.4	15.9	16.3	10.3
Eastern Canada Offshore	0.5	71.8	72.3	0.0
Western British Columbia	0.0	10.9	10.9	0.0
US Total	**244.7**	**2,860.6**	**3,105.3**	**1,652.5**
Canada Total	**61.3**	**807.6**	**868.8**	**519.1**
US and Canada Total	**306.0**	**3,668.1**	**3,974.1**	**2,171.6**

Source: ICF

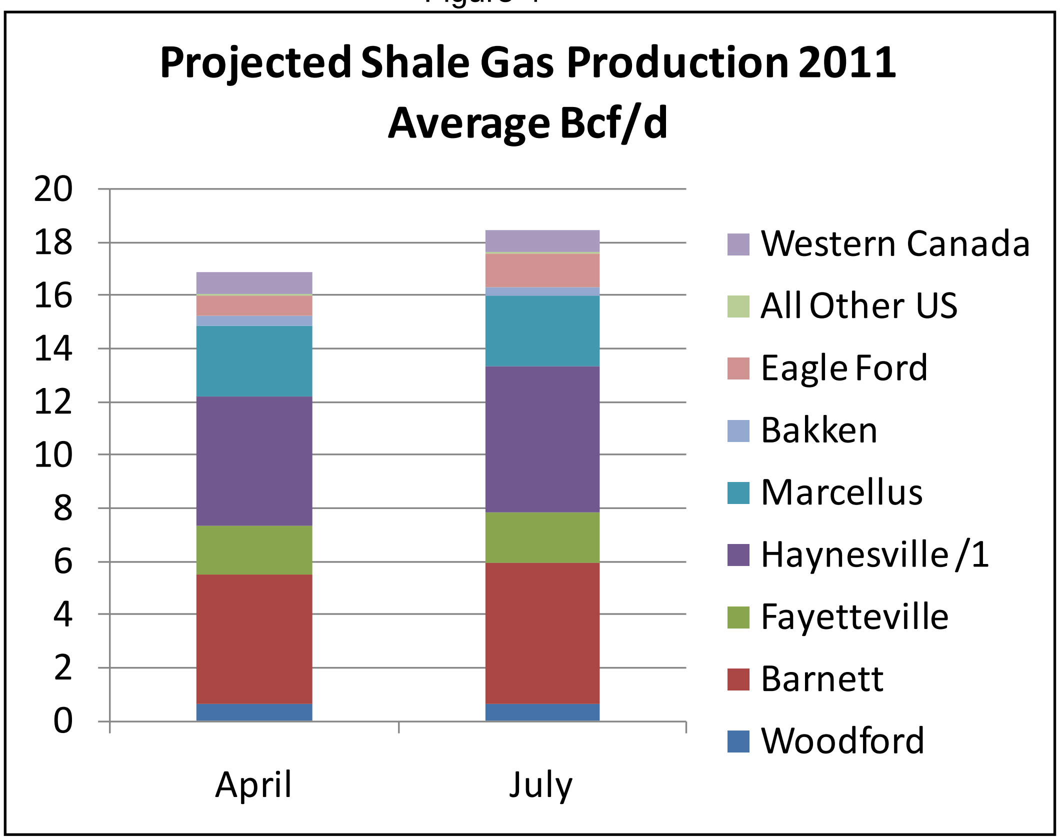
1. Shale Resource is a subset of Total Remaining Resource
2. Eastern Interior includes Marcellus, Huron, Utica, and Antrim shale.
3. Reference case assumes drilling levels are constant at today's level over time, reflecting restricted access to the full resource development.

The additional year into the development of shale gas resources has yielded concrete results. Despite relatively low gas prices, gas production from the Marcellus formation increased by 103 percent from 2009 to 2010, reaching almost 1.6 billion cubic feet per day (Bcfd). With the 2011 drilling activity currently underway, ICF projects that

Marcellus gas production will grow an additional 73 percent over 2011. The production is projected to average about 3 Bcfd by the end of 2011.

Shale gas production is growing in other locations, as well. Based upon drilling activity in the first half of the year, ICF's estimates for total shale gas production in 2011 have increased to an annual average of 18.5 Bcfd. ICF projects that North American shale gas production as of December 31, 2011 will be approximately 20.4 Bcfd. Moreover, shale gas production growth continues to exceed expectation. Figure 4 shows a comparison of the estimates from our July Base Case and April Base Case produced earlier this year, as well as the rapid nature of the changes that are occurring in natural gas production.

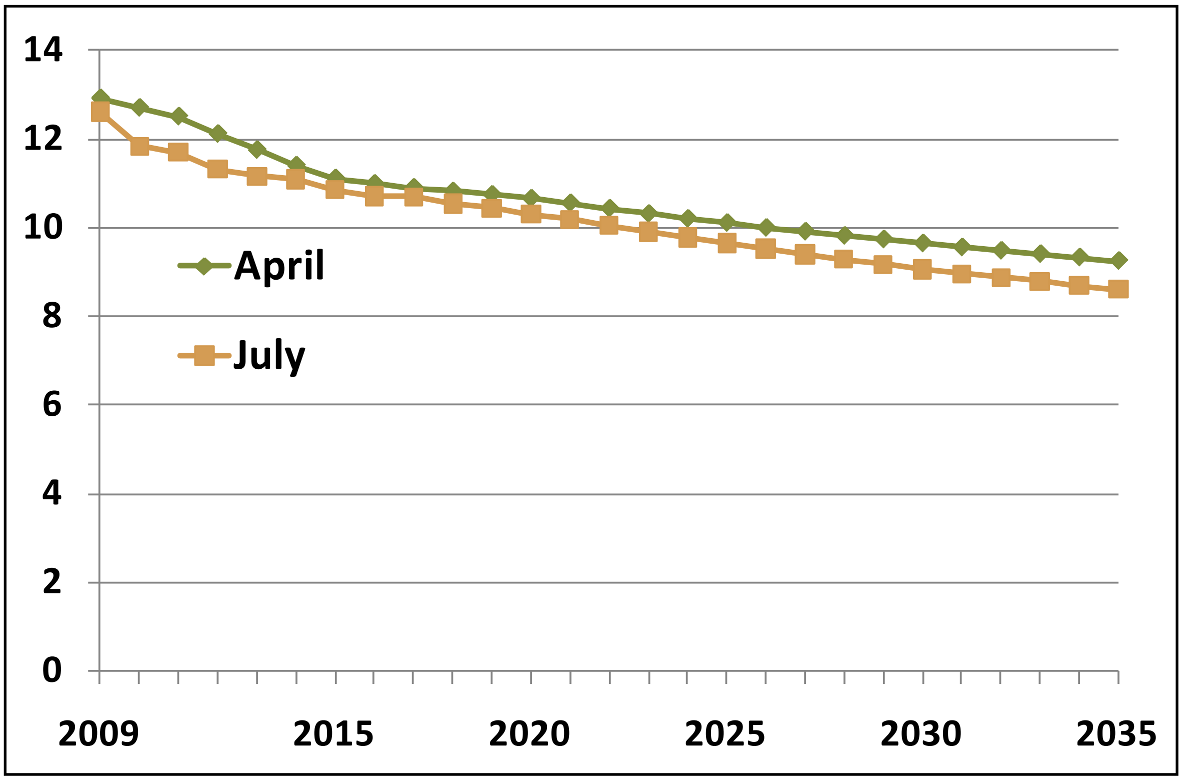
Figure 4



Source: ICF

Not all gas supply developments have been positive, however. The 2010 Report also identified a declining conventional resource production trend in the WCSB. Our analysis indicates that the rate of decline has been somewhat larger than previously anticipated as shown in Figure 5.

Figure 5
WCSB Conventional and Tight Production,
Average Annual Bcf per day



Source: ICF

While conventional gas production has continued to decline, a trend that will persist over the foreseeable future, shale gas potential in western Canada is also being developed. ICF projects robust development of shale resources in western Canada, principally the Horn River and Montney formations. In the July Base Case, ICF projects western Canadian shale production to grow to more than 2 Bcfd by 2015 and to 4.6 Bcfd by 2025. This represents an increase of 4.1 Bcfd from 2010.

Even with robust development of western Canadian shale resources, the total gas volume available for transport to market is projected to decline nearly 45 percent, from

10.0 Bcfd in 2010 to 6.6 Bcfd in 2025. Declines in conventional resource production capabilities; the increase in gas requirements in Alberta to meet industrial, power generation, and oil sands development; and the modest liquefied natural gas (LNG) exports together more than offset total shale production growth. Figure 6 presents the production versus amount of gas available for export out of western Canada.

Figure 6

Alberta and British Columbia Balance (Bcfd)

	2010	2015	2020	2025
Demand	**15.6**	**14.9**	**15.6**	**15.5**
Consumption	5.1	6.2	6.9	7.6
Storage Injections	0.5	0.5	0.5	0.6
LNG Exports	-	0.5	0.8	0.8
Pipeline Exports	10.0	7.6	7.3	6.6
Supply	**15.7**	**15.0**	**15.7**	**15.6**
Production	15.2	14.4	15.1	15.0
Storage Extractions	0.48	0.48	0.54	0.52
Pipeline Imports	0.01	0.03	0.07	0.09
Pacific (contiguous)	0.01	0.03	0.07	0.09
Balancing Item*	**0.06**	**0.08**	**0.12**	**0.12**

Source: ICF

* “Balancing Item” represents the difference between total supply and demand, which is comprised mainly of unaccounted for losses and flared gas.

As in any projection, there are a number of important assumptions that are included in the ICF Base Case projection, which are subject to varying levels of uncertainty. The resolution of the issue of the TCPL Mainline tolls is a critical uncertainty that will affect the balance of supply and demand in Alberta and British Columbia, and the amount of gas available to be transported via TCPL and other pipelines to markets outside of the province. The data presented in Figure 6 assumes that the tolls on the TCPL mainline are consistent with the tolls that were approved for 2011.

Subsequently and as discussed later in this paper, TCPL has filed an application for tolls that are significantly lower than those assumed in the balance presented in

Figure 6. It is not possible to know with certainly how this critical issue will be resolved at this time. However, to the extent that the mainline tolls are lowered from current levels and stabilized in a sustainable manner that can last for the next decade or more, the level of gas production from Alberta and British Columbia can exceed the values shown in Figure 6. Lower tolls on the TCPL Mainline would result in a higher “netback” price for gas production in the WCSB, making development of the Canadian shale resource more economic. Conversely, if a resolution to the TCPL tolls proceeding does not result in sustainable and competitive tolls, the development of the Canadian shale resource will depend largely upon access to world LNG markets through exports from the Pacific coast.

Assuming that the tolls that result from the ongoing proceeding are lower than is assumed in the July Base Case, the volume of gas available for transport on the TCPL mainline would also be affected. Base upon preliminary analysis, ICF estimates that TCPL mainline tolls would have to be below the level of the proposed 2012 tolls and sustained at that level for an extended period to stabilize the throughput on the mainline east from Alberta even at its current level. None of the many toll scenarios examined by ICF to date project TCPL mainline throughput returning to 2009 levels on a sustained basis.

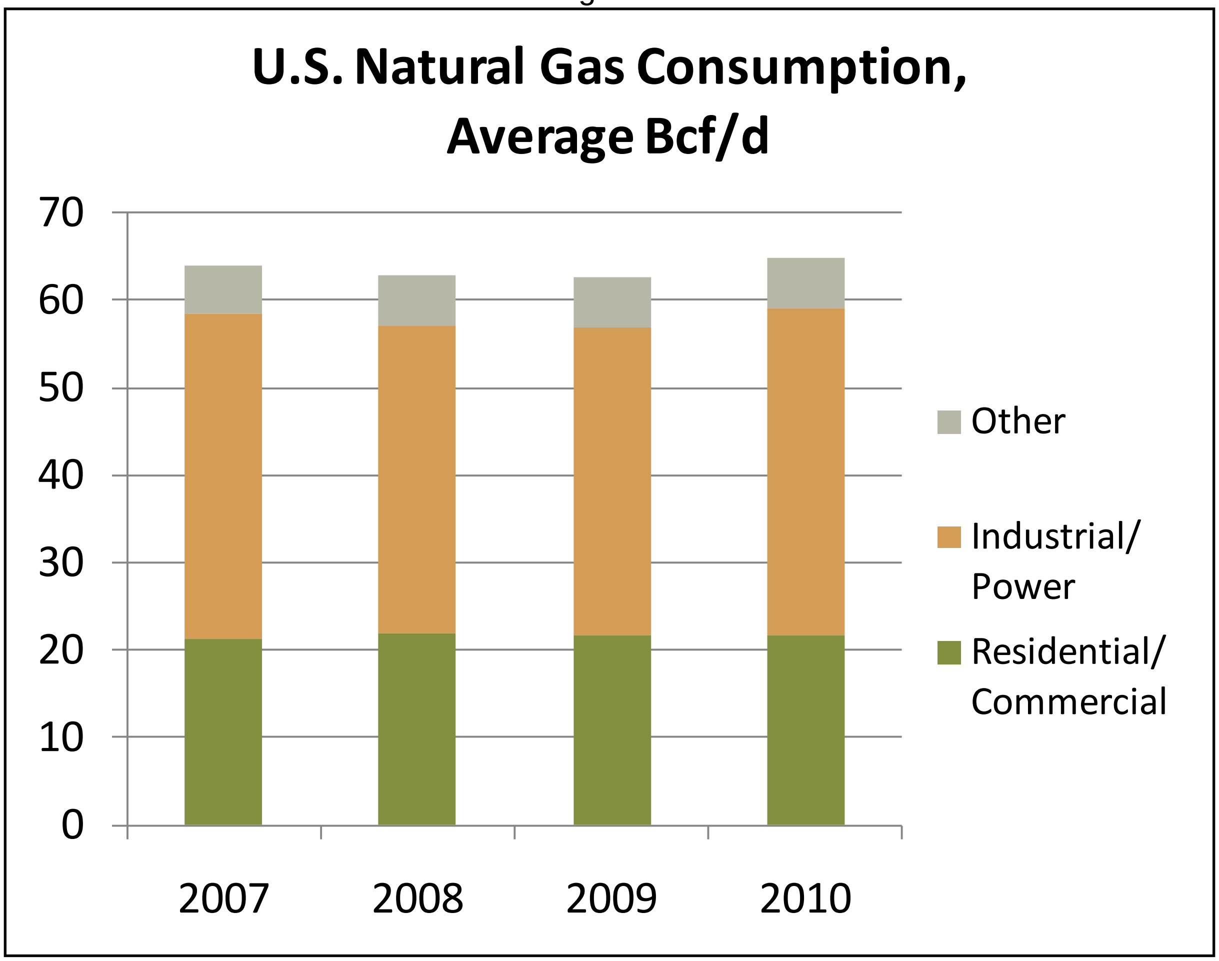
Natural Gas Demand

In the last year, three factors that were not anticipated in the 2010 Report have also affected gas consumption:

1) A slower than anticipated economic recovery.
2) Slightly larger than anticipated gas-fired generation dispatch, at the expense of coal generation, due to lower gas prices.
3) A significant increase in gas use in the production of ethanol.

These factors have divergent influences on gas consumption, with slow economic growth resulting in lower than expected growth of gas demand, and increased gas consumption associated with the dispatch of gas generation and larger ethanol production. Figure 7 presents the updated composition of gas demand in the United States.

Figure 7



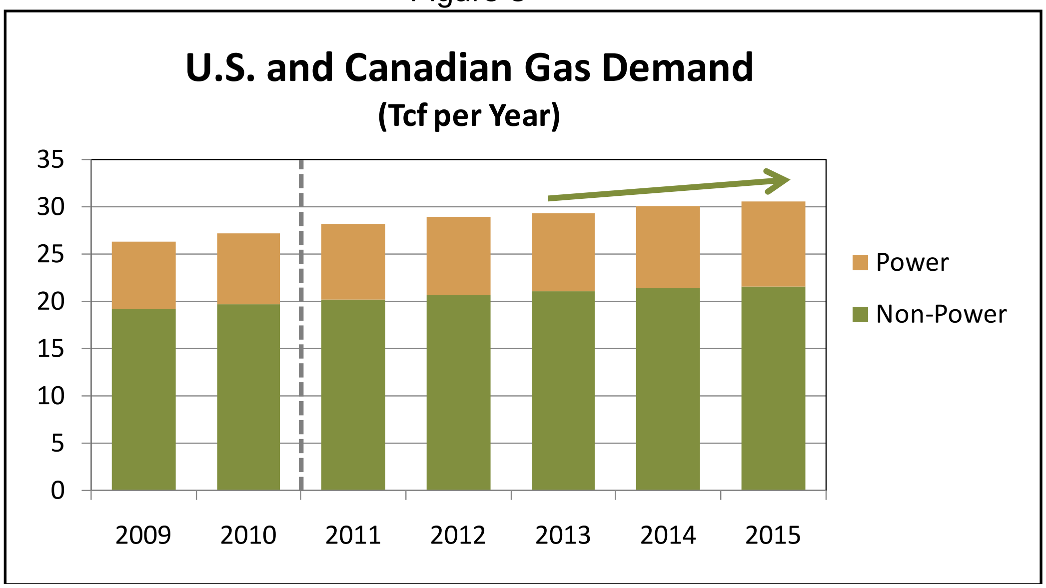
Source: ICF

Figure 8 presents the projected gas consumption growth path. The anticipated growth averages 1.6 percent per year from 2010 through 2035.

Looking forward, uncertainty with regard to the North American economy's overall performance persists. Concerns regarding Europe's sovereign debt issues and possible implications for international financial markets, as well as the U.S.' fiscal conditions and government deficit concerns raise questions with regard to growth potential for Canada and global markets. While the current ICF Base Case assumes that economic growth will stabilize and a "double-dip" recession will be avoided in Canada and the United States, the forecast risk is clearly negative.

In the intermediate term, ICF remains convinced that the primary source of natural gas demand growth arises from growth in gas-fired generation. Increases in the number of residential and commercial customers are largely offset by the increasing use of energy efficient appliances, thereby offsetting demand growth. While there is dramatic growth in the number of natural gas vehicles – projected to double by 2030 – the volume of gas consumed remains modest because of the low base. The growth in gas vehicles in the Base Case is limited to fleets and centrally fueled vehicles.

Figure 8



Source: ICF

With respect to power generation gas consumption, ICF has moderated the near-term projection of increased consumption. The change is driven primarily by lower electricity consumption (due to lower economic growth) and the assumptions regarding any actions to address greenhouse gas emissions in the United States. There appears to be somewhat greater certainty regarding actions addressing greenhouse gas emissions in the power generation sector in Canada than in the United States. Actions to replace coal generation in Ontario with gas and renewable generation are proceeding. In the United States, however, there is less certainty. The ICF Base Case assumes that actions in the U.S. will be delayed until 2020, which is a change from the earlier case.

This is important to Canadian gas markets because of the size of the U.S. gas market for power generation and the impact it has on the overall balance for gas supply and demand.

Gas consumption growth in Ontario and throughout North America is contingent upon a return to modest economic growth. The ICF Base Case assumes that the economies of Canada and the United States will grow at an average annual rate of 2.8 percent per year from the first quarter of 2012 and continue at that pace through the projection period.

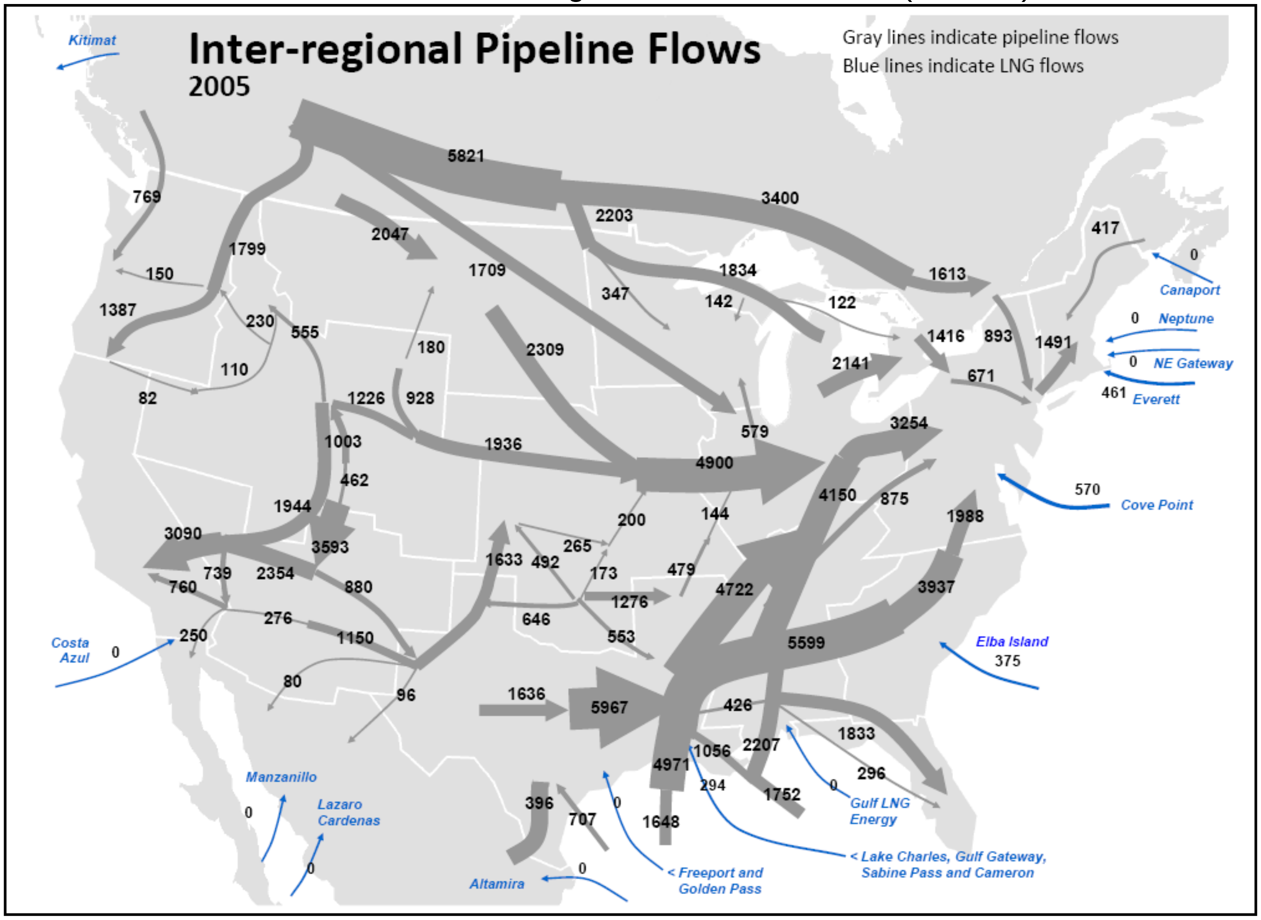
Notwithstanding that assumption, there is considerable forecast risk associated with economic growth. In a recent speech, Federal Reserve Chairman Ben Bernanke identified two factors that are resulting in lower growth than would be anticipated in the economic recovery: persistent housing market weakness and the residual impact of the 2008 financial crisis.[2] In addition, concerns regarding sovereign debt in Europe, recovery in Japan, and political "gridlock" within the United States government all influence the bleak outlook for international growth. Combined, these factors have significantly increased the possibility of a "double-dip" recession, which would stall natural gas demand growth.

Shifting Patterns of Interregional Natural Gas Flows

Shifts in gas production and the differences in regional gas demand growth result in changes in interregional flows of natural gas. Figures 9 and 10 illustrate the patterns of gas movement for 2005 and 2010, respectively. In both years, the movement of gas from the Western Canadian Sedimentary Basins (WCSB) along the TCPL Mainline to markets in eastern Canada and Northeast markets of the United States is clearly evident. But close examination indicates that a significant change has occurred between 2005 and 2010.

2 Chairman Ben S. Bernanke At the Federal Reserve Bank of Kansas City Economic Symposium, Jackson Hole, Wyoming, August 26, 2011

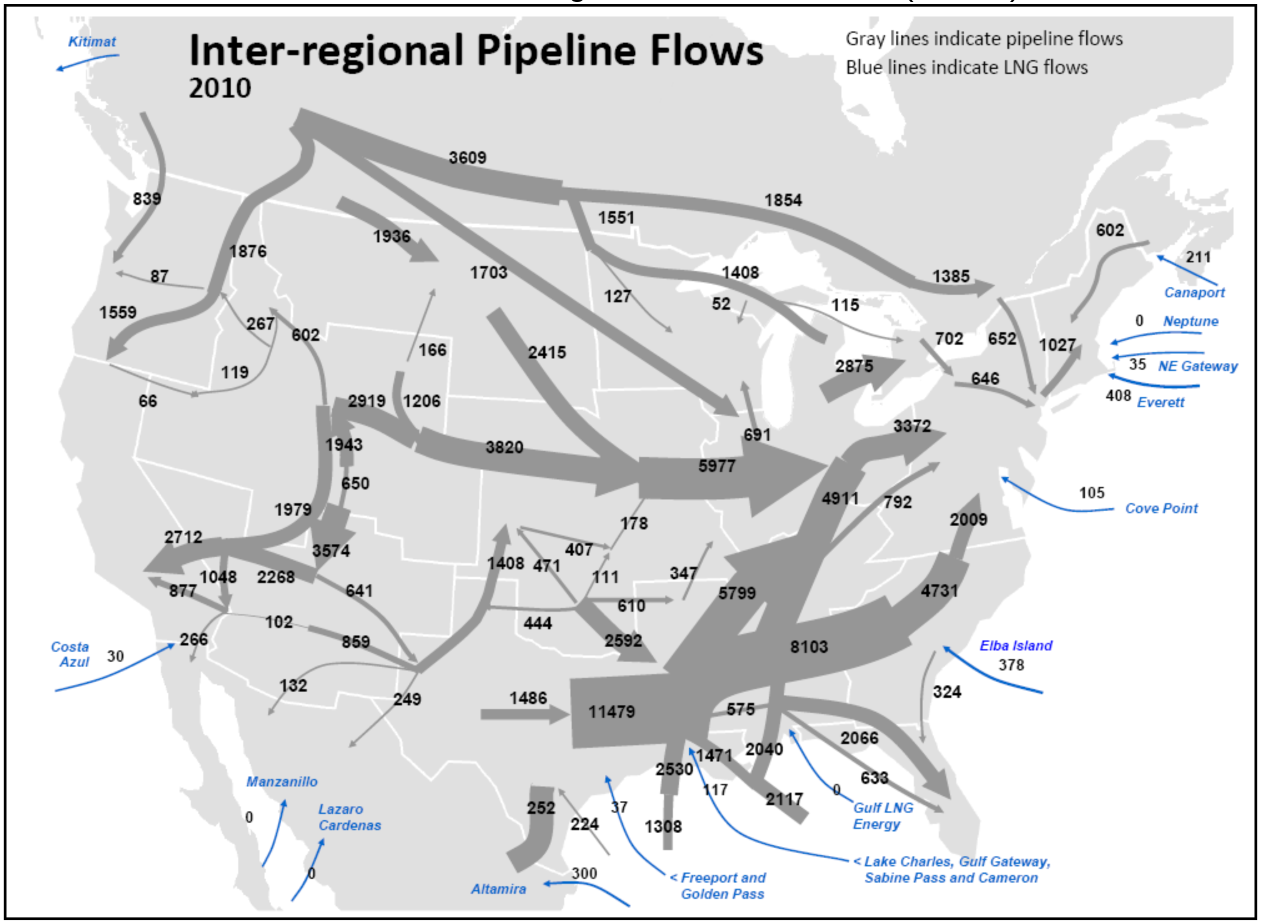
Figure 9
North American Inter-regional Gas Flows 2005 (MMcfd[3])



Source: Historic data complied by ICF

[3] Million cubic feet per day

Figure 10
North American Interregional Gas Flows 2010 (MMcfd)



Source: ICF

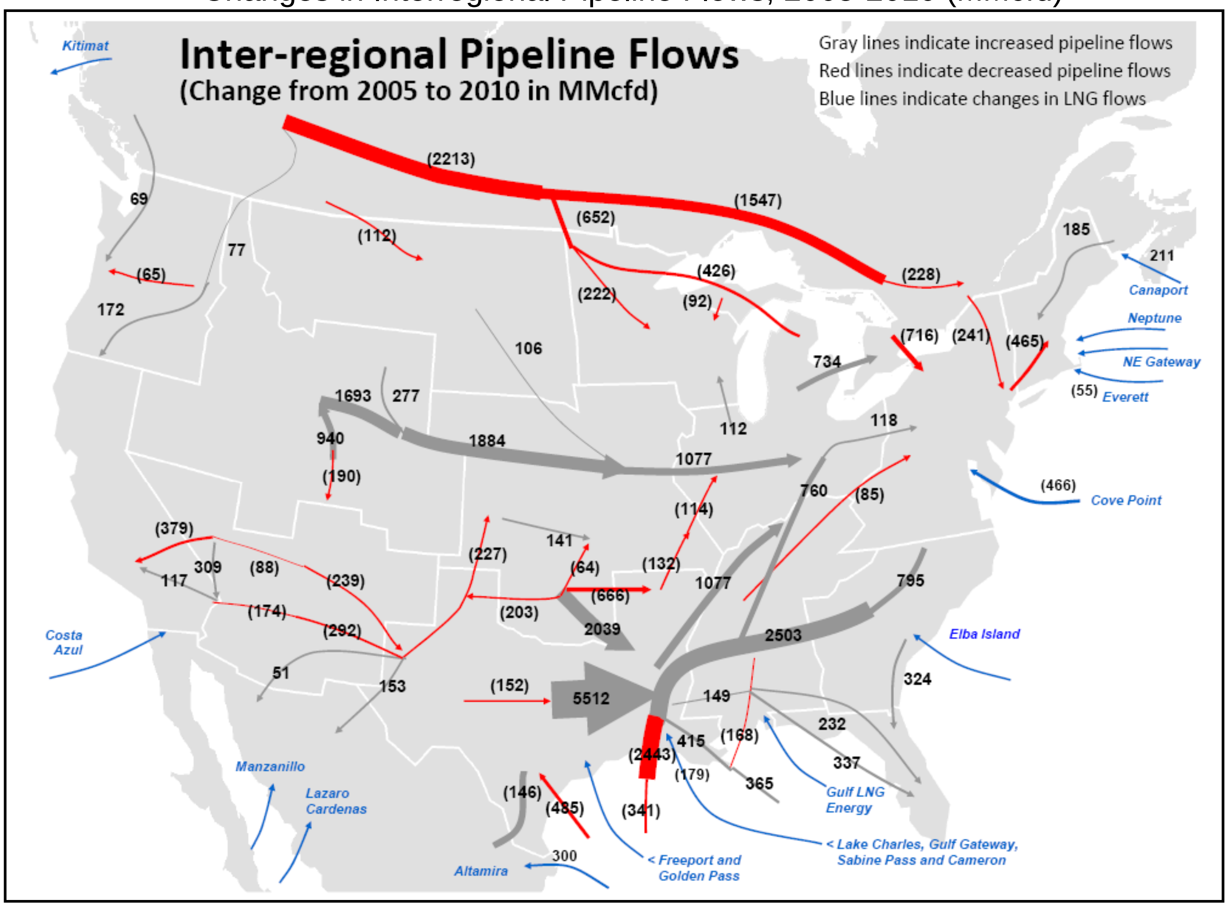
Figure 11 illustrates the changes from 2005 to 2010. The chart reflects the difference between the interregional flow of gas in 2010 and the flow in 2005. Increases in flow are represented by the gray arrows. Decreased flows in 2010 from the 2005 level are presented as red arrows.

Flows on the TCPL Mainline declined dramatically over the period. There are several reasons behind this decline. A combination of declining conventional production in the Western Canadian Sedimentary Basin (WCSB) and increased demand for gas in Alberta to develop the oil sand resources has reduced the supplies available to be shipped on TCPL. Moreover, with the Alliance Pipeline and Northern Border Pipeline providing an alternate path for gas to flow from western Canada at lower cost than the

TCPL path to the U.S. Midwest, the decline in the availability of gas production for export out of the WCSB to other Canadian provinces and U.S. markets was concentrated onto the TCPL Mainline.

Increased production in the U.S. Rockies led to construction of the Rockies Express (REX) pipeline, which increased the flow of gas from the Rockies eastward. The growth of shale gas production in the midcontinent area created a surge of flow eastward, which more than replaced the decrease in Gulf of Mexico offshore production. Increased power sector gas demand in the U.S. Southeast meant that more of the gas flowing eastward from the midcontinent remained in the Southeast. The growth of Marcellus shale gas production has reduced flows from the Gulf Coast into the U.S. Northeast, freeing up gas supplies for the Southeast.

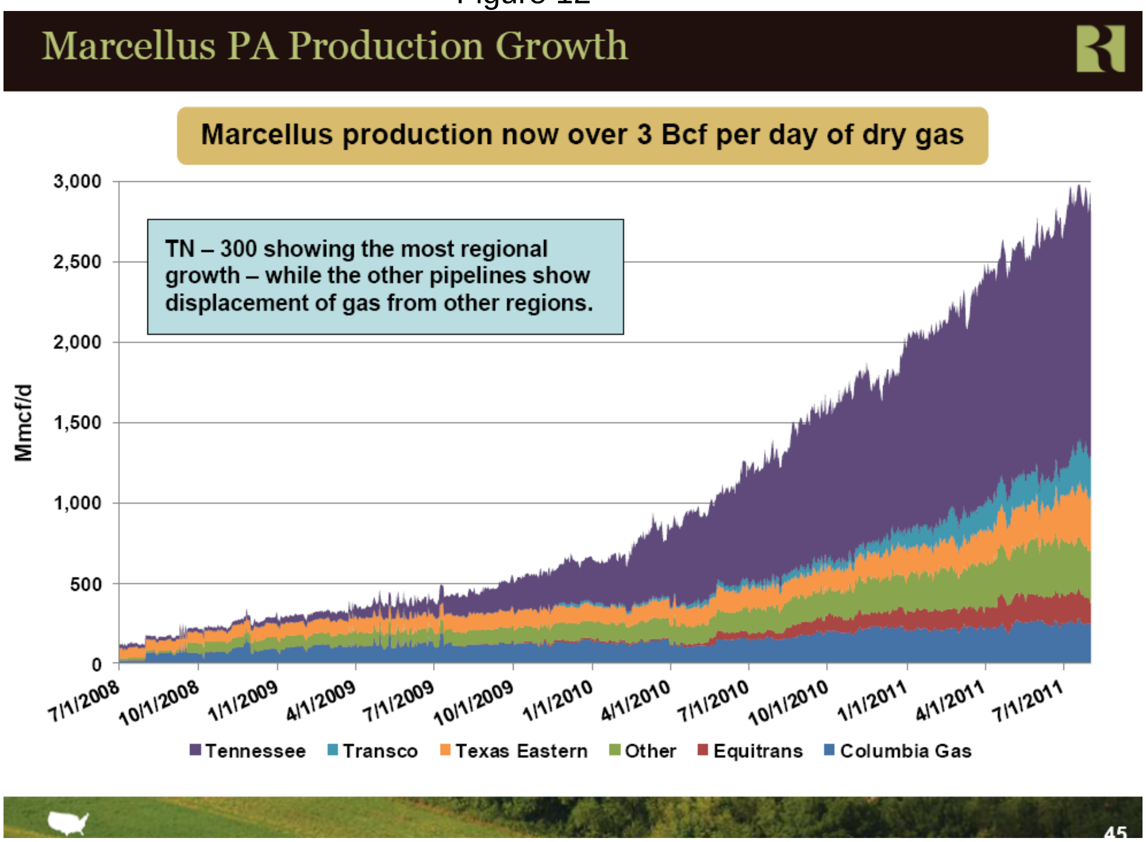
Figure 11
Changes in Interregional Pipeline Flows, 2005-2010 (MMcfd)



Source: ICF

Growth in gas production from the Marcellus formation is increasing the amount of gas available on pipelines in the U.S. Northeast. Figure 12 presents data showing the pipelines receiving gas from the growing production of Marcellus gas in Pennsylvania. These large gas volumes displace gas that has historically flowed from Ontario into the United States. These volumes are also available to flow north into Ontario via pipelines that have expanded and/or modified facilities to allow for firm transportation service to customers in Ontario.

Figure 12



Source: Range Resources

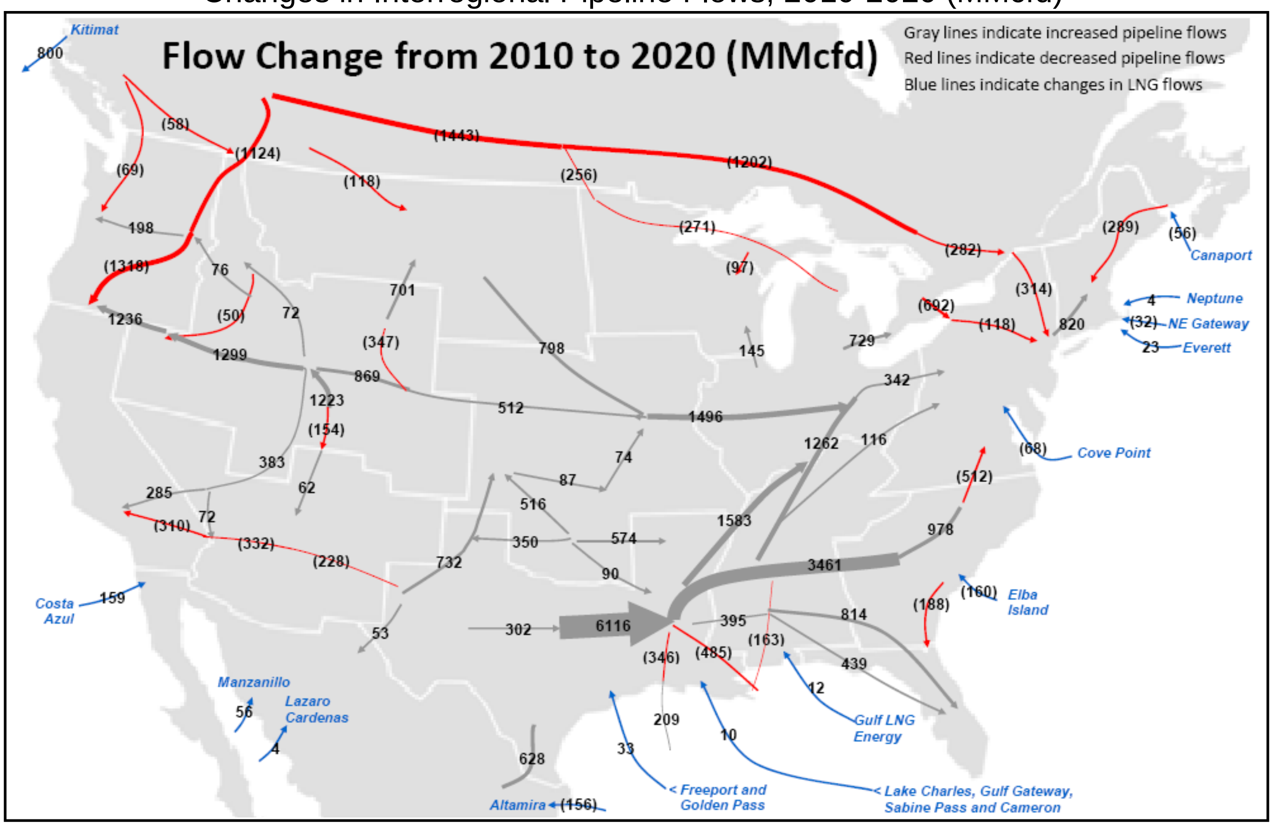
Changes in the flow of gas on the pipeline network are having an impact on the firm transportation contract portfolios held by shippers. As the throughput on the TCPL Mainline fell, shippers re-contracted to other short-haul paths to access other supplies.

Similarly, the development of Marcellus gas in proximity to gas markets in Ontario and the U.S. Northeast will result in a review and adjustment of firm contract portfolios. Upon the expiration of existing contracts, shippers will evaluate and may choose alternate arrangements that more closely match the altered flow patterns and market conditions.

ICF projects that the forces that have led to the historical shift will continue. Figure 13 projects that the flow changes will occur between 2010 and 2020. These trends indicate a shift in the gas sources for eastern Canada, with less reliance upon gas from the WCSB. Diversification to other gas sources is expected to continue, and is reflected in the further decline in gas flows along the TCPL Mainline and through the Great Lakes Pipeline.

Figure 13

Changes in Interregional Pipeline Flows, 2010-2020 (MMcfd)



Source: ICF

The pattern of interregional flows has important implications for Ontario and Union Gas. In percentage terms, Ontario is receiving less gas from the WCSB and more from a diversified portfolio of sources, including gas from shale formations in eastern Texas, Arkansas, Louisiana, and Oklahoma, either via transportation arranged by Ontario shippers or indirectly through purchases at downstream, liquid market centers. Gas produced in the U.S. Rocky Mountains also contributes to this diversified portfolio.

In addition, the historical flow of gas on an annual average basis from Ontario into the U.S. Northeast is dramatically reduced. Northeast consumers are increasingly looking to supplies from Marcellus production rather than gas delivered through Ontario import points. While shippers may keep some capacity for use on peak winter days, overall load factors will be reduced in the short term and in the medium term, other pipeline projects may provide the peak day requirement. The magnitude of this impact, projected in the current ICF Base Case, is larger than that included in the 2010 Report.

The growth in production in Marcellus, the Rocky Mountains, and the shale resources of Texas, Louisiana, Oklahoma, and Arkansas combine to make significantly more gas available to midcontinent markets, including Chicago and Michigan. With this abundance of supply, ICF projects that there will be economic pressure to increase gas flows from Michigan into Ontario to offset the declines on the TCPL Mainline. This is a continuation of the trend that has occurred over the last five years, which has provided Ontario with competitively priced gas. ICF projects that this will continue even with the increases in availability of gas from the Marcellus and eventually Utica formations. With projected future declines of gas available from the TCPL mainline, incremental supply will be required to keep gas in Ontario competitively priced in the future.

As increasing volumes of Marcellus gas and other sources of unconventional gas are increasingly made available to the market, shippers will review and may adjust contract portfolios to access these supplies. Some of the pattern changes have already taken place, a trend that will likely continue.

With these changing patterns, it is highly likely that shippers will continue to make adjustments in transportation contract portfolios as current contract obligations expire. For Union Gas transportation services, this pattern of re-contracting may be problematic. Some or all of the existing contracts for firm service across the Union system held by shippers serving markets in the U.S. Northeast is “at risk” upon expiration of current contracts.

TCPL Tolls and Regulatory Uncertainty

As identified in the 2010 Report and confirmed by ICF's current analysis, throughput on the TCPL Mainline from the WCSB to Ontario and points east have continued to decline just as new options for gas supply have emerged. The decline in throughput has resulted in increases in both long-haul and short-haul tolls on TCPL. With these increases, TCPL service has become less competitive, relative to other options, leading a number of gas shippers to seek other options either to limit exposure to TCPL rate risk or to source more competitive options.

The projected declines in throughput create significant challenges for TCPL and shippers on the pipeline. Over the last two years, TCPL and its shippers have participated in an intensive effort to develop acceptable tolls that address the threat that TCPL service is not competitive. Despite this effort, a settlement has not yet been reached.

On September 1, 2011, TCPL proposed modifications in the toll structure to increase the competitiveness of gas transported east on the mainline. While it is not clear precisely what will be approved by the NEB, ICF concludes that the "forecast risk" that creates uncertainty for Union Gas is likely to persist over the near term.

The September 1st filing focused on deferral of costs and adjustment of depreciation in order to attempt to restrain the toll increases that accompany reductions in contract and throughput volumes. In order to stabilize the throughput on the mainline, it will be necessary to significantly reduce the tolls from 2011 levels, reversing the increases that have occurred in recent years.

The rising transportation costs also have dynamic impacts on the economics of gas exploration and production in the WCSB. As discussed earlier, this is critical to the development of the shale resources in British Columbia. The competitiveness of any gas source is based upon the delivered cost of gas to the market. With increasing transportation costs, there is pressure on the "netback" price for gas production. All else equal, a lower "netback" price at the wellhead reduces gas drilling activity and, consequently, reduces gas volumes available for pipeline transport.

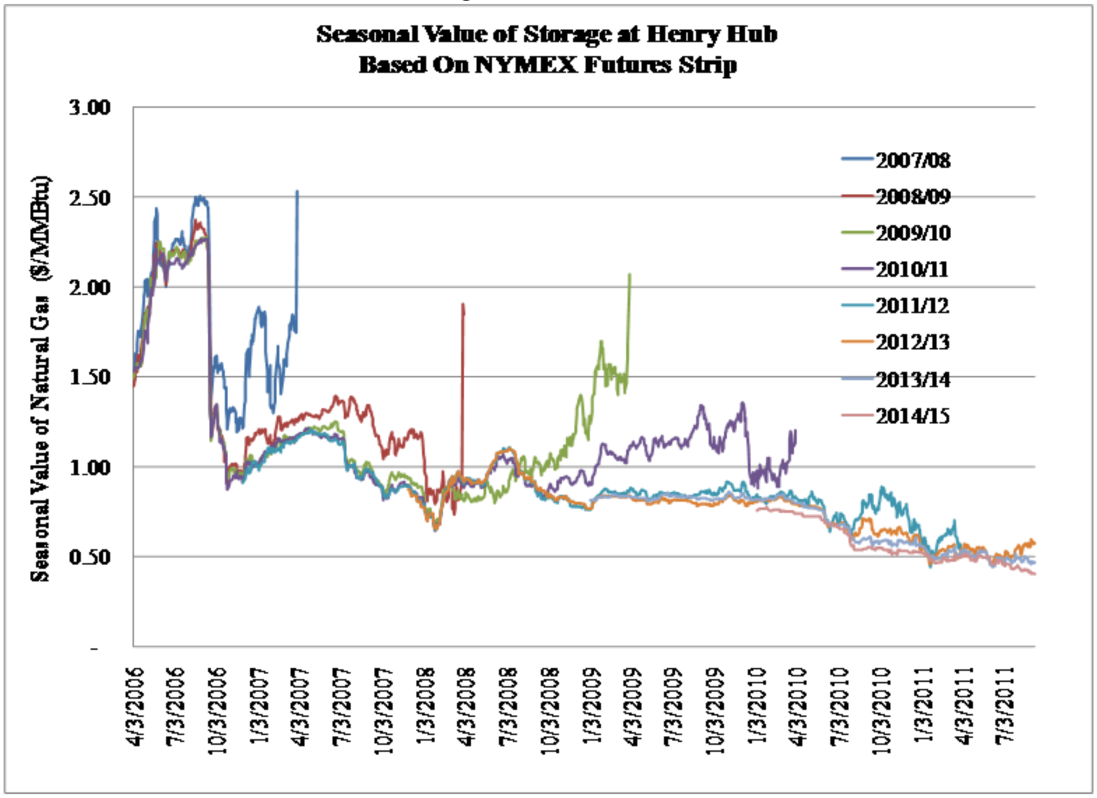
Along with the discussion surrounding the level of long-haul tolls, options have been considered that adjust the allocation of costs between long-haul and short-haul service. Such actions have the potential to make short-haul service less competitive and increase costs to Ontario consumers that have benefited from newly available gas supply options. To the extent that additional costs are shifted to short-haul options, consumers in Ontario will see higher delivered costs of gas. As well, U.S. Northeast markets that currently source supply in Ontario may consider other more economic options as TCPL short haul tolls for path through Ontario increase.

Natural Gas Storage

The soft economic growth and increased gas production have had a significant impact on the economics and market value of natural gas storage. Current forward markets reflect only small values for the spread between winter gas commodity prices and prices for the storage injection season. These “seasonal price spreads” form the primary component of the “intrinsic value” of storage.

Figure 14 presents a time series of the seasonal price spreads for natural gas in the forward market. For each year, the average futures price for the injection season months is subtracted from the average price for the withdrawal season months. This metric measures the value of storing gas as determined by the participants in the gas futures market. The figure below shows this declining trend described above.

Figure 14



Source: ICF

At the same time, natural gas commodity prices have "decoupled" from volatile oil prices and have not exhibited the volatility that contributes to the economic value of storage. These factors, as well as the development of new storage capacity available to the market, have resulted in substantially softened gas storage market prices over the last two years, a trend that is likely to persist. With continuing growth in gas supply resulting in a more flexible market and lower prices, ICF predicts that 2011 market conditions are likely to persist.

Conclusions

The trends in the North American gas markets present challenges to all market participants. For Union Gas, these changing market condition impact gas supply purchase decisions, as well as the sale of transportation services and value of storage.

There are a number of factors that create significant uncertainty regarding the throughput and utilization of Union Gas facilities through 2018. The combination of an unclear economic outlook, uncertainty regarding TCPL tolls, a relatively soft market for storage, and considerable uncertainty with regard to re-contracting transportation by Ex-Franchise shippers together present significant challenges to Union and the Board.

As increasing volumes of Marcellus gas and other sources of unconventional gas continue to be made available to the market, shippers are likely to adjust contract portfolios to access these supplies. The changing flow patterns are already apparent. With these changing patterns, it is highly likely that shippers will continue to evaluate and make adjustments in transportation contract portfolios as current contract obligations expire. This includes the desire for Canadian gas consumers to receive additional volumes of gas through Michigan so as to lower delivered gas costs.

With all of the various options available to shippers, the pattern of re-contracting may be problematic for Union Gas transportation services. Some or all of the existing contracts for firm service across the Union system held by shippers serving markets in the U.S. Northeast are “at risk” upon expiration of current contracts.

ALLOCATION OF COSTS BETWEEN UNION'S REGULATED AND UNREGULATED STORAGE OPERATIONS

In the Natural Gas Electricity Interface Review ("NGEIR") Decision (EB-2005-0551), the Board determined that the market for Union's ex-franchise storage services was a competitive market and, as such, Union would no longer be subject to rate regulation for those services. At that time, Union made changes in accounting for capitalized costs, Property, Plant and Equipment ("PP&E"), and income taxes related to unregulated storage operations. These changes were required because, post-NGEIR, Union's unregulated storage activities no longer met the criteria for rate-regulated accounting and the unregulated portion of PP&E was no longer included in utility rate base.

In the EB-2005-0551 decision (p. 73, emphasis added), the Board found that:

> *"…. functional separation is not necessary. The evidence before the Board is that it would be costly and difficult to establish a functional separation of utility and non-utility storage, and there was no evidence to suggest that there would be significant benefits from such a separation. To the extent there may be concerns regarding the integrated operations, these will be addressed through the reporting requirements set out in section 5.4. We also conclude that Union's current cost allocation study is adequate for the purposes of separating the regulated and unregulated costs and revenues for ratemaking purposes. The Board agrees with the Board Hearing Team that it is important to ensure that there is no cross-subsidization between regulated and unregulated storage. However, the Board is content that with its findings on the treatment of the premium on short-term storage services (Chapter 7) Union will have little incentive to use the cost allocation for purposes of cross-subsidy."*

The Board's Decision did not require Union to functionally separate its regulated and unregulated storage operations. The Board did find that Union's Board-approved 2007 cost allocation methodology was adequate for the purposes of separating unregulated storage assets and related O&M expenses in the financial records. It is on the basis of the Board-approved 2007 cost allocation study that Union has separated the costs associated with its regulated and unregulated storage operations since the NGEIR decision.

The Board determined, as part of the NGEIR Decision, that Union shall reserve 100 PJ of storage space at cost based rates to accommodate in-franchise growth (EB-2005-0551, Decision with Reasons, p. 83). Based on the above conclusion, Union used the Board-approved 2007 cost allocation methodology to separate storage assets, general plant and related O&M expenses for 62.5 PJ of unregulated storage capacity from the 100 PJ of regulated storage capacity.

In EB-2010-0039, Union filed evidence explaining the cost allocation methodologies used to separate costs between Union's utility and non-utility businesses. As part of the settlement agreement in EB-2010-0039, Union hired an independent consultant, Black & Veatch ("B&V"), to review Union's cost allocation methodologies.

B&V concluded that "the conceptual underpinnings and resulting methodologies upon which Union's cost allocation process is based are well-conceived, thorough and reasonable in their treatment of storage-related plant and expenses".

Union's approach to the separation of the financial information related to the unregulated storage operations from the financial information for the utility operations is consistent with the cost allocation methodology approved by the Board in the 2007 cost allocation study. Union's approach is also consistent with the Board's conclusion in the NGEIR Decision that the cost allocation study is adequate for the purposes of separating regulated costs and revenues for ratemaking purposes.

Union's cost allocation study included at Exhibit G, and subsequently the proposed rates at Exhibit H, only address Union's regulated business. The 2013 revenue requirement for Union's regulated business is derived through direct assignments to the regulated business for distribution activities and through allocations for activities and projects that include both regulated and unregulated costs prior to being input into the cost allocation study. For activities and projects that have both regulated and unregulated components (e.g. O&M, Asset Integrity Management), Union has provided both the total company costs and the costs assigned to the regulated business.

Below is a summary of the allocation methodologies used to separate the costs between Union's regulated and unregulated businesses.

Summary of Allocation Between
Union's Regulated and Unregulated Storage Operation

EB-2005-0520 Board-approved cost allocation methodology	**Methodology used to allocate costs to Union's unregulated storage operations**
Existing Underground Storage Assets	Existing Underground Storage Assets
Certain assets (specific structures, measuring and regulating and compression assets) in the Dawn Station yard are installed solely for transmission purposes and are directly assigned to the transmission function. These assets include the meter runs into the Dawn-Trafalgar system, metering at Tecumseh, Oil Springs and TCPL, and the Great Lakes header. The Dawn Plant E compressor is not directly assigned to transmission in Union's Board-approved cost allocation study.	Consistent with the Board-approved 2007 cost allocation methodology, the meter runs into the Dawn-Trafalgar system, metering at Tecumseh, Oil Springs and TCPL, and the Great Lakes header are directly assigned to the transmission function. In addition, the Dawn Plant E compressor, which was installed to provide transmission compression from Dow-Moore into the Dawn-Trafalgar system, was directly assigned to transmission.
Compression-related assets that are not directly assigned to transmission provide both storage and transmission services at Dawn and are allocated between storage and transmission functions based on horsepower requirements. Union's Board-approved 2007 cost allocation study allocated 44.4% of Dawn compression related costs to the storage function and 55.6% of Dawn compression-related costs to the transmission function. These factors were applied to total compression-related costs.	Compression-related assets were allocated at the individual asset level. Outboard storage compressors located at Union's storage pools are directly assigned to storage. As noted above, the Dawn Plant E compressor was directly assigned to transmission. Compression-related costs of assets that are used to provide storage and transmission services were split between storage and transmission based on a horsepower allocation that excluded the outboard storage compressors and the Dawn Plant E compressor. This resulted in an adjusted Board-approved horsepower allocation that allocates 52.7% of Dawn compression-related costs to the storage function and 47.3% of Dawn compression-related costs to the transmission function. These factors were used for the one-time separation of the assets.

Measuring and regulating equipment assets that are not directly assigned to transmission provide both storage and transmission services at Dawn and are allocated between storage (26%) and transmission (74%) based on the forecasted activity into and out of Dawn. The storage costs are classified as deliverability. Storage deliverability costs are allocated to rate classes based on design day demands from storage (the NETFROMSTOR allocator), which allocated 39.2% of these storage costs to ex-franchise storage services. The result is that 10.2% of allocated M&R costs are allocated to ex-franchise storage services.	For measuring and regulating equipment assets that are not directly assigned Union used the 2007 Board-approved split of assets between storage and transmission and allocated the storage assets to unregulated storage using an average storage space and deliverability allocator of 37.7%. The result was an allocator for measuring and regulating equipment of 9.9% for unregulated operations. These factors were used for the one-time separation of the assets.
Storage land, land rights, buildings, wells and lines and base pressure gas are classified between space, deliverability and system integrity, and are allocated to ex-franchise storage services based on space, deliverability and system integrity allocators.	Storage assets were allocated to unregulated storage using an average storage space and deliverability allocator of 37.7%. These factors were used for the one-time separation of the assets.
<u>General Plant</u>	<u>General Plant</u>
In Union's Board-approved 2007 cost allocation study, general plant assets are assigned to the storage function in proportion to net plant and O&M and classified in the same manner. Costs are allocated to ex-franchise storage services based on the space, deliverability, commodity and system integrity allocators.	General plant is separated into two categories to determine the allocation factor for the unregulated storage operations. The vehicle and heavy equipment allocator was determined using the relative asset value of vehicles used in the Storage & Transmission Operation compared to the total value of vehicles and heavy equipment for all of Union (11.9%). Vehicle assets applicable to Union's unregulated storage operations were allocated using the average space and deliverability factor used for other storage assets (37.7%). This results in an allocation for

	vehicles of 4.5% for unregulated operations. The second category of general plant includes all other categories of general plant. These assets were allocated to the unregulated storage operations using an allocation factor that combines storage assets and storage O&M. The percentage of unregulated storage to total plant (3.32%) is averaged with percentage of allocated support costs to total O&M (2.52%). This results in an allocation for other general plant of 2.92% for unregulated operations.
Working Capital	Inventory of stores, spare equipment and prepaid and deferred expenses are allocated to unregulated storage in proportion to the allocation of total storage net plant. Cash working capital is calculated using regulated O&M and cost of gas.
Taxes	Property Taxes Property tax related to the assets at Dawn is allocated between unregulated storage and regulated utility operations in proportion to the allocation of total storage gross plant. Deferred Tax Drawdown The deferred tax drawdown is allocated based on the split of the December 31, 1996 plant balance between regulated and unregulated. The result is an allocation factor of 10.3%. Accumulated Deferred Taxes The accumulated deferred tax balance associated with the December 31, 1996 plant balance was allocated using the same allocation factor as

	described under the deferred tax drawdown allocation (10.3%).
Operating & Maintenance Expenses	Operating & Maintenance Expenses
O&M is allocated based on an analysis of activities or in the same manner as the underlying assets. Costs are allocated to ex-franchise storage services based on the space, deliverability, commodity and system integrity allocators.	Actual O&M related to the operation of the storage facilities was allocated to the unregulated storage operation using the same allocators applied to the assets for that facility. Administrative and general expenses and benefits in support of unregulated storage operations were allocated in proportion to storage O&M. O&M costs related to the development of new storage assets are assigned based on an estimate of time spent annually on the development of unregulated projects. O&M costs related to the Regulatory department for development of new storage assets, are assigned based on an estimate of time spent annually on the development of unregulated projects.
Cost of Gas	Cost of Gas
The compressor fuel budget is allocated to storage and transmission in proportion to forecast volume. Storage fuel is allocated to ex-franchise storage services in proportion to forecast volume.	The storage compressor fuel forecast is allocated based on estimated unregulated storage activity.
Unaccounted for gas (UFG) costs are allocated to storage and transmission in proportion to forecast volume. Storage UFG is allocated to ex-franchise storage services in proportion to forecast volume.	The unaccounted for gas costs in the 2013 forecast are allocated based on estimated unregulated storage activity. The UFG allocation factor is the ratio of unregulated storage volumes to Union’s total storage and transportation volumes.

UNION GAS LIMITED

BUDGET PROCESS (CAPITAL & OPERATING)

Union's annual budget, expressed in the form of Budget Financial Statements, is derived from five major planning sub-processes: Capital, Operating and Maintenance ("O&M"), Revenue, Cost of Gas, and Financial Statements.

This section of evidence describes the sub-processes specifically related to:

1/ O&M Budget Process

2/ Capital Budget Process

3/ Preparation of the Budget Financial Statements

Revenue and cost of gas forecasting process are described at Exhibit C1, Tab 1 to Tab 4 and Exhibit D1, Tab 1 respectively.

1/ O&M BUDGET PROCESS

The O&M budget process is designed to provide a forecast of the company's future operating costs. A budget is prepared with input from each administrator group and is approved by the group's respective senior management.

There are five major steps in the O&M budget process:

1) Identification of budget assumptions
2) Preparation and distribution of budget instructions
3) Preparation of operating budget
4) Senior management review and approval
5) Consolidation

These steps are described in greater detail below:

1) IDENTIFICATION OF BUDGET ASSUMPTIONS

The Financial Forecast department provides the budget assumptions to the O&M department. The assumptions include, but are not limited to, inflation and salary and wage increases. The assumptions are compiled from a variety of sources but are based largely on the projections of Consensus Economics or in the case of salary and wage increases, the Human Resources department in conjunction with Towers Watson. These assumptions are included in the Budget Instructions that can be found at Appendix B. They were updated in August 2011 and are reflected in the updated Economic Assumptions which can be found at Appendix A.

2) PREPARATION AND DISTRIBUTION OF BUDGET INSTRUCTIONS

The assumptions, along with the timetable and instructions for completing the budget are documented and distributed to all budget process participants. A copy of the O&M budget instructions has been provided at Appendix B.

3) PREPARATION OF OPERATING BUDGET

Demand/revenue level information is obtained in order to calculate O&M related expenditures. This includes items such as new customer attachments.

Details of affiliate services revenue and costs are also obtained. These amounts relate to services provided by one affiliate to one or more other affiliates. The figures used in the budgeting process are based on the Service Level Agreements ("SLAs") in place between Union and its affiliates.

Each budget area starts with expense figures from the last approved budget. In order to meet Union's overall productivity target, goals are established at the administrator level. For the 2012 and 2013 period, a productivity improvement target of 1.0% per year is to be achieved by each functional area.

In addition to savings from improved productivity, an inflation factor is added to the historical expense figure, which is based on market indicators. The budget that is established (i.e. prior year -productivity + inflation) is then adjusted to reflect the impact of new program additions or deletions as well as any existing programs that will be materially changed. The costs of the various projects are then assigned to the relevant budget expense line items to ensure proper identification of costs.

A review of planned activities is completed for the budget period detailing how manpower will be utilized in order to accomplish the work plan. Additional staffing requirements are considered, as is the need to employ consultants or contract employees in order to complete the required workload in a timely, cost effective manner. Wage and overtime costs, including merit increases, are then determined.

Non legislated benefit costs are determined through consultation with an independent HR consultant. These costs tend to change at different rates than the average inflation figure. Inflation and discount rates (for pension expense) are applied as required to determine the pension expense. At this point, the benefit cost component of the proposed budget has been developed.

Based on the resources required to carry out the work plan, relevant material, equipment and vehicle costs are incorporated into the detail.

4) Senior Management Review and Approval

The budgets are reviewed at successively higher levels of management, with modifications made on an iterative basis as required. A final budget for each area is developed and approved by the executive responsible.

5) Consolidation

The budget prepared by each administrative area is then consolidated into the overall corporate budget.

2/ CAPITAL BUDGET PROCESS

The capital budget process produces a forecast of capital expenditures required to expand system capacity to meet customer demands for additional service, to maintain the existing facilities, to ensure Union provides safe, reliable service to customers, and to facilitate the company's goal of providing cost effective service to customers through the use of technological enhancements.

There are six major steps in the capital budget process:

1) Preparation and distribution of budget instructions

2) Project identification

3) Project specifications and costing

4) Technical/economic review

5) Senior management review and approval

6) Consolidation

These steps are described in greater detail below:

1) PREPARATION AND DISTRIBUTION OF BUDGET INSTRUCTIONS

The Financial Forecast department provides the budget assumptions to the Capital department. The assumptions include, but are not limited to, inflation and foreign exchange. The assumptions are compiled from a variety of sources based largely on the projections of Consensus Economics or in the case of interest during construction ("IDC"), the OEB's website. Relevant assumptions to this process are included in the 2012 and 2013 Capital Budget Instructions found at Appendix C.

The assumptions, along with the timetable and instructions for completing the forecast, are distributed to all budget process participants. Training of budget participants also occurs so that everyone is aware of both what is required of them and the assumptions that are to be used to formulate the budget. The capital guidelines and instructions are contained within the copy of the “Budget Kick off Meeting” presentation found at Appendix C.

2) **PROJECT IDENTIFICATION**

Capital expenditures are required for five primary reasons.

1. Special programs that result in the need for capital expenditures.
2. System integrity expenditures required to maintain or enhance the integrity of the company’s plant through changes to codes/regulations or commonly accepted industry practices. Union must ensure that it is in compliance with codes and regulations governing the industry.
3. System replacement expenditures required as a result of requests from municipalities and others under the terms of franchise or other occupancy agreements. Union is contractually obligated to comply with these agreements and the resulting modifications required.
4. Capital expenditures to replace plant, vehicles and equipment, computer hardware and software as a result of age, condition, obsolescence, etc.
5. New project requirements are identified through the demand/revenue planning process and the gas supply planning process.

3) **PROJECT SPECIFICATIONS AND COSTING**

Individual requests for inclusion in the capital budget are prepared by the business area managers. Prior to the authorization of each project, an internal approval process is initiated whereby justification/evidence of the need for the project must be made, along with a consideration of alternate means of achieving the goal. Specific information is required regarding in-service dates, IDC calculations, accounting and risk classification, pipe lengths, and cash flows.

A proposed capital expenditure must also conform to company standard pricing and economic justification.

Each item requested must also conform to established engineering specifications, in relation to design, construction and method of installation.

4) TECHNICAL/ECONOMIC REVIEW

Each item is reviewed to ensure adherence to established economic and technical standards. The economic feasibility test is discussed in further detail in Exhibit A2, Tab 3, Schedule 2.

5) SENIOR MANAGEMENT REVIEW AND APPROVAL

Reviews of the need, timing and economic justification of capital budget requests are then carried out at successively higher levels of management. The overall level of the capital budget is also reviewed to confirm the availability of the capital dollars required.

The overall capital budget is also reviewed in the context of the overall financial forecast results and customer impacts.

6) CONSOLIDATION

The capital budget is then consolidated into the overall corporate budget.

3/ PREPARATION OF THE BUDGET FINANCIAL STATEMENTS

The preparation of the budget financial statements is, to a large extent, a culmination of information prepared during the "upstream" budget processes.

- O&M received from the O&M budget process.
- Revenue received from the demand/revenue planning process.
- Cost of gas, inventory, DCB payable and balancing gas received from the gas supply planning process.
- Capital spending, gross plant, accumulated depreciation, depreciation expense, property tax and capital cost allowance received from the capital budget process.

There are five major steps in the budget financial statements process:

1) Review and Verification of Input
2) Preparation of Financial Statements

3) Review and Approval
4) Submission to Spectra
5) Presentation to Board of Directors

1) REVIEW AND VERIFICATION OF INPUT

The information is reviewed to ensure consistent and correct application of budget assumptions, prior to incorporation into the financial forecast. In addition, the budget information is reviewed for overall reasonability. In the event the information does not reflect the appropriate assumptions or appears unreasonable, follow-up discussions will occur with upstream process participants. Otherwise, the information is incorporated into the budget financial statements.

2) PREPARATION OF FINANCIAL STATEMENTS

Once all upstream information has been validated, the budget financial statements are created. The utility earnings, rate base, capital costs and overall revenue deficiency/sufficiency schedules are prepared after the corporate financial statements have been prepared.

3) REVIEW AND APPROVAL

The corporate and utility budget financial statements are presented to Union's senior management for review and approval.

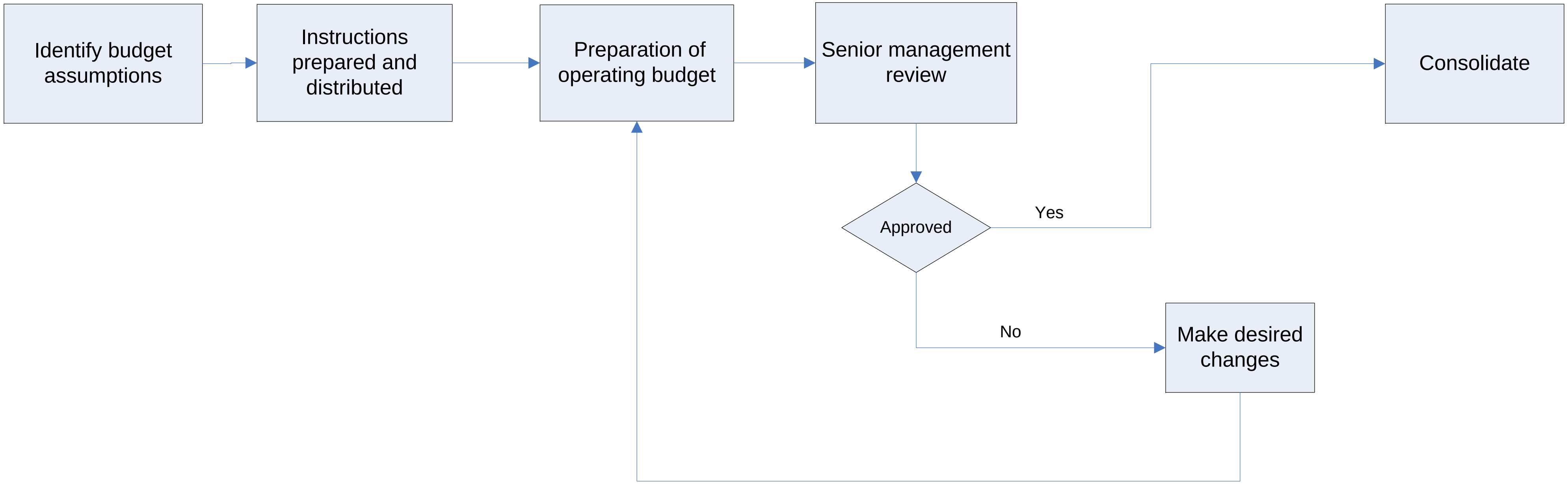
4) SUBMISSION TO SPECTRA

The corporate financial statements are presented to Spectra Energy Corp executive for review and approval.

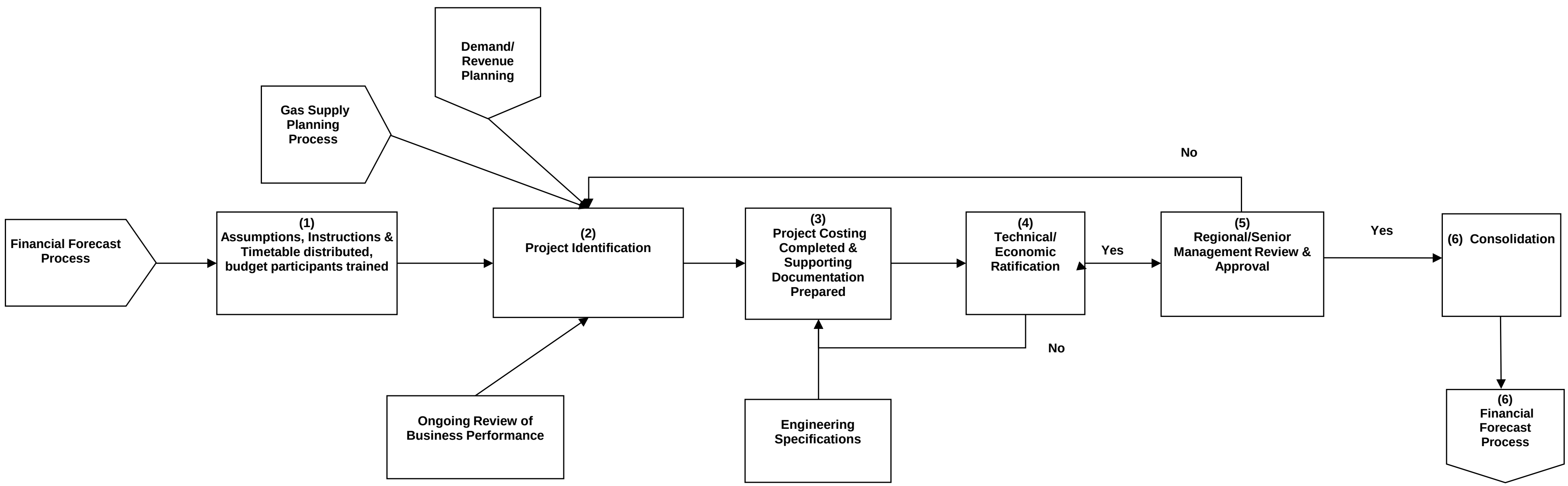
5) PRESENTATION TO BOARD OF DIRECTORS

The corporate financial statements are presented to Union's Board of Directors for review and approval.

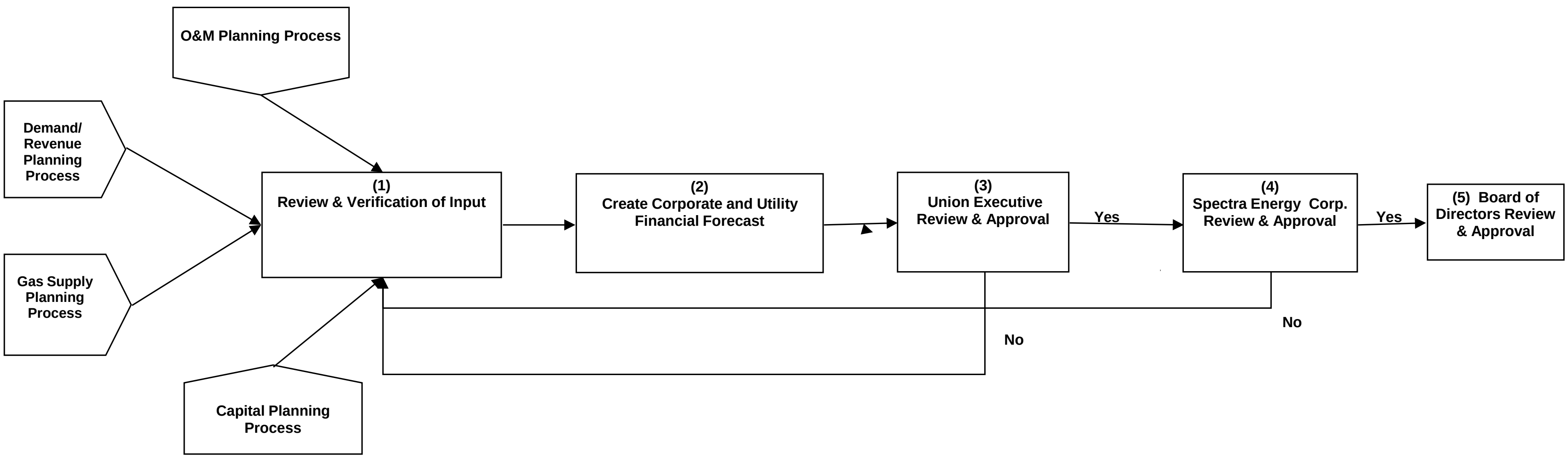
O&M Budget Process



Union Gas Limited
Capital Budget Process



Union Gas Limited
Preparation of Corporate Financial Statements



UNION GAS LIMITED

Economic and Key Assumptions
For the Year Ended December 31

Line No.	Description	2012 (a)	2013 (b)
	Economic Outlook:		
1	GDP - Canada [1]	2.7%	2.7%
2	GDP - USA [1]	3.3%	3.3%
3	FX rate US $ = 1 Canadian $ [1]	1.019	1.019
4	Inflation rate [1]	2.1%	2.1%
5	Salary and Wage Increase	3.0%	3.5%
6	Unemployment rate [1]	7.3%	7.3%
7	Housing starts - Canada [1]	178,000	203,270
8	Housing starts - Union Franchise Area	16,847	19,360
9	Weighted Average Cost of Gas ($/$10^3$ m^3)	202.61	202.61
10	Price of gasoline ($/L)	1.31	1.31
11	Interest During Construction (CWIP)	4.29%	4.29%

Note:
(1) Source: Consensus Economics, January 2011.

Filed: 2011-11-10
EB-2011-0210
Exhibit A2
Tab 3
Schedule 1
Appendix B

Union Gas Ltd.

2012 – 2014
O&M Budget Instructions

February 2011

Table of Contents

2012 – 2014 O&M Budget Timeline

Mar 21, 2011	• SAP V.58 open Mar 21, 2011 for 2 budget detailing
Group 1 [(1)] Apr 15, 2011	• Overhead and unregulated settlement rule updates provided to Penny Boyle
Group 1 Apr 29, 2011	• VP sign off, SAP detailing complete, variances & templates to Penny Boyle
Group 2 [(2)] May 16, 2011	• Overhead and unregulated settlement rule updates provided to Penny Boyle
Group 2 May 31, 2011	• VP sign off, SAP detailing complete, variances & templates to Penny Boyle

Notes:

(1) Group 1 includes: BDS&T, Tax, Internal Audit, Global & Fleet, Procurement, Legal, Executive, Regulatory, Government Relations

(2) Group 2 includes: Dist Ops, ECS, MCC, IT, ITI, HR, Finance, Insurance, Affiliates

2012- 2014 Assumptions & Guidelines

Guideline

The expectation is that year-over-year O&M increases will be relatively small and be primarily attributed to revenue growth or regulatory commitments. The basis for the 2012, 2013 and 2014 O&M budgets should be the prior year budget:

- plus merit/promo increases
- plus inflation
- plus/minus foreign exchange impacts
- less 1% productivity (including business transformation savings which should continue to be specifically identified)
- plus/minus program additions and deletions
- plus costs related to growth opportunities such as distribution customer attachments and expansion capital
- plus/minus regulatory commitments (e.g. DSM)

Exceptions must be fully supported and approved by senior management. O&M increases related to distribution customer attachments and expansion capital must correspond to the costs included in project economics. Conversely, O&M savings identified in project economics should also be included in the 2012 & 2013 O&M budgets.

Assumptions (preliminary only – subject to change)

	2012	2013	2014
WACOG (based on Jan 2011 QRAM)	$202.610/10*3m*3	$202.610/10*3m*3	$202.610/10*3m*3
Inflation	2.1%	2.1%	2.1%
Attachment Forecast (Gross) **Attachment Forecast (Net)**	20,380 18,180	22,491 20,291	22,653 20,453
Customer Growth ***-Distribution Operations @61%*** ***- Marketing & Customer Care @39%***	<u>$105.71</u> $64.77 $40.94	<u>$105.71</u> $64.77 $40.94	<u>$105.71</u> $64.77 $40.94
Exchange	$1.00 USD = $1.019 CAD	$1.00 USD = $1.019 CAD	$1.00 USD = $1.019 CAD
Merit Increase	3.5%	4.0%	4.0%
Promotion /Adj. (Non-Union)	0.5%	0.5%	0.5%
Vacancy Allowance	3.0%	3.0%	3.0%
Employee Expenses (+/- program adds / deletions)	2010 actual plus inflation	2012 budget plus inflation	2013 budget plus inflation
DSM Escalator	0%	0%	0%
Productivity	1%	1%	1%
SAP Version	V. 58	V58	V61

SAP Structure and Allocations

Primary Cost Elements

When detailing your 2012 & 2013 O&M Budget, please ensure that the appropriate PCE is used for each cost type. The updated PCE Table has been uploaded on the SharePoint site. Please see the SharePoint site to get a complete listing of all available PCEs with description.

Cost Object Groupings

The Cost Object (CC and IO) groupings table for 2011 is available on the SharePoint. Upon completion of the 2012 budget cycle, the CC and IO groupings will be modified to reflect current organizational structures and an updated appendix will follow at that time. However, if you are aware of any organizational changes that may impact your 2012 budget, please let us know and we will work with you to create an alternate reporting structure.

Overhead Capitalization Settlement Updates

As part of the budget process, all overhead capitalization rules should be reviewed and updated (if necessary). The guidelines are provided in Appendix A. Requests for changes to settlement rules must be provided to Penny Boyle no later than:

Group 1: end of day April 15, 2011

Group 2: end of day May 16, 2011

Unregulated Allocation Settlement Rules

As part of the budget process, unregulated cost allocations should be reviewed and updated (if necessary). The guidelines are provided in Appendix B. Requests for changes to settlement rules must be provided to Penny Boyle no later than:

Group 1: end of day April 15, 2011

Group 2: end of day May 16, 2011

Loadings (Direct Capital Costs)

Please refer to your capital budget guidelines regarding loadings. If applicable, O&M will detail in SAP the offset / credit for loadings and provide you the details at that time

Salaries & Wages

(1) Salaries and Wages PCE's

The best indicator of the appropriate PCE to use for budgeting Salaries and Wages is an employee's band or grade level. Refer to table below.

Description	Position Type	Grade / Band Level	PCE Salaries & Wages	PCE Overtime
Executive	07	21 – 25	410001	410101
Management	14	07 - 14	410001	410101
Technical / Analyst	09	04 – 06	410002	410102
Clerical Unionized	10	South 1 – 9 North CFC 8 -11 or North UOF 2 – 10	410003	410103
Clerical Non-Union	12	1 – 3	410003	410103
Hourly Unionized	11	Union Code not 'NON' Too many grades to list	410004	410104
Casual Temp Contract Employees	any	Any	410009	410009

2) Overtime

Please follow the link below and refer to the H.R. policies on the portal for the rates and employee eligibility for overtime pay.

https://thesource.spectraenergy.com/hr/employees/Documents/HR%20Policies/Spectra%20Energy%20Canada/Canada_Overtime_Non-Union.pdf

(3) Vacancy Allowances

When budgeting for salaries and wages, a provision of 3% for vacancies is recommended (where applicable). Vacancies result from any number of reasons including:

- employees leaving due to acceptance of a new position within the company
- the time between adding a new role and filling the position
- attrition (employees leaving the organization)

(4) Incentive Programs

Dollars budgeted for incentive programs such as STIP are included in the Human Resources budget. However, there are some bonus programs specific to departmental objectives that are budgeted differently. These should continue to be budgeted in the same manner as in the past.

(5) Pay Periods

Attached for your reference is a payroll schedule outlining the pay periods for 2012 & 2013. Please ensure that the pay periods per month are taken into account when detailing salary and wage related costs.

Note: the following are based on Pay Deposit Dates for 2012.					
	South			North	
	Unionized (Weekly)	Non-Union Clerical & Tech. (Bi-Weekly)	Management & Supervisory	Hourly	Salaried
January	4	2	2	2	2
February	4	2	2	2	2
March	5	2	3	2	3
April	4	2	2	2	2
May	5	3	2	3	2
June	4	2	2	2	2
July	4	2	2	2	2
August	5	2	3	2	3
September	4	2	2	2	2
October	4	2	2	2	2
November	5	3	2	3	2
December	4	2	2	2	2
Total	**52**	**26**	**26**	**26**	**26**

Note: the following are based on Pay Deposit Dates for 2013.					
	South			North	
	Unionized (Weekly)	Non-Union Clerical & Tech. (Bi-Weekly)	Management & Supervisory	Hourly	Salaried
January	5	2	2	2	2
February	4	2	2	2	2
March	4	2	3	2	3
April	4	2	2	2	2
May	5	3	2	3	2
June	4	2	2	2	2
July	4	2	2	2	2
August	5	2	3	2	3
September	4	2	2	2	2
October	5	3	2	3	2
November	4	2	2	2	2
December	4	2	2	2	2
Total	**52**	**26**	**26**	**26**	**26**

SAP gives you the option of using “Distribution Keys” to incorporate these pay periods in your budget detailing. If desired, select the appropriate distribution key to tell the system how to divide the planned value over the fiscal accounting periods. Most commonly used keys are 0 for manual distribution; 1 for equal distribution; 2 for distribution as before; Z11E for weekly unionized; Z11F Bi-weekly South, Hourly North and Salaried North; Z11G for Management & Supervisory.

Other

Monthly Expense Distribution

Salaries and wages should be cash flowed using the pay periods provided below. Other expenses should be cash flowed based on the month you expect the actual expense to be incurred.

Employee Expenses

Centre of Excellence: Employee expenses should be budgeted using the information provided in the budget model.

Affiliate Revenue

Lucy Griffioen (ext 2233) will be contacting you for this information.

$1000 Rule: O&M vs. Capital

The minimum spend in order to be eligible for capitalization is $1,000. If an item has a value of less than $1,000 and is purchased and maintained as a set with a total value greater than $1,000, then it should be capitalized. Please refer to the Allowable Capital Costs document uploaded on the SharePoint.

Foreign Exchange Impact

Please use the foreign exchange rate specified in the Assumptions table. Please complete the sensitivity analysis provided in your budget package template.

2012-2014 Budget Share Point

Share Point (link below) will be used as the central repository of the 2012 - 14 forecast process. In order to ensure consistency in the forecast all submissions and retrievals (handoffs) should be done via the SharePoint site. Upon completion of any forecast component it should be uploaded to the “Submit Files Here” document library. Documents will then be transferred to the appropriate library by Carla-Jo McLaren or Penny Boyle. If you have any questions regarding the SharePoint site please contact Carla-Jo McLaren or Penny Boyle.

http://caneastsp01/accounting/2012-14budget/default.aspx

Budget Package

Completed (SAP and templates) and VP approved budgets are due to O&M no later than:

Group 1: **end of day April 29, 2011**.

Group 2: **end of day May 31, 2011**

This section provides instructions on how to fill out each tab in your budget packages.

2011 Gross O&M Tab

This tab helps you calculate your Gross O&M budget using 2010 Gross O&M Budget as the base / starting point.

Column 1

Populate this column with your 2011 O&M Budget detailed in SAP. This column will be used as the base for calculating the 2012 O&M Budget.

Columns 2-5

These columns are highlighted and require user input. Use these columns to layer on Merit, Progression and Inflation increases on top of 2011 Gross O&M Budget based on the rates provided in the assumptions section.

Column 6

This column is highlighted and requires user input. This column is to be used for any 2012 additions / deletions to be incorporated in budget over and above Merit, Progression and Inflation. A few examples of activities that may be identified in this column are:

- FTE adds / deletes
- Vacancy Allowance
- BTO Impacts
- Labor dollars that were budgeted in O&M in 2010 but will be charged directly to Capital in 2011
- Software and Hardware costs budgeted in Capital in 2010 but will be charged to O&M in 2011 or vice versa
- Employee Expenses budgeted in O&M in 2010 but will be charged to capital in 2011 or vice versa
- Etc.

Please provide variance explanations for dollars included in this column in the area provided below the schedule

Column 7

This column calculates the total 2011 Gross O&M Budget and must reconcile to what’s detailed in SAP.

Columns 8 – 19

The same process is repeated for the 2013 and 2014 budget in Tab 1.

Full Time Equivalent (FTE) and Headcount Guidelines & Reporting Requirements

Please complete Tab 2 with the FTE and Headcount at the end of December for each year. This information requirement is different than previous years and is based on the reporting requirements for both Houston and the 2013 rate case. Please provide variance explanations for year over year changes in FTE and headcount.

For a description of FTE vs. Headcount please see Appendix C.

FX Tab

Please use this tab to provide a sensitivity analysis by cost type assuming the exchange rate specified in the template.

Appendix A: Overhead Capitalization Settlement Updates

Functions:

Functions that have costs allocated to capital overheads generally fall into one of the three categories noted below:

Non-Project-Specific Capital Support
Activities in this category are specifically focused on capital but cannot be charged to specific projects, either because it is impractical or costly to do so, or because the function is related to capital projects generally rather than to specific or identified projects.

Support and Oversight of Activities Directly Charged to Capital Projects
Activities in this category include the administration and supervision of construction departments and plant accounting.

Support Functions
This category covers the functions that support the departments that perform capital related work. These support functions will include, but are not necessarily limited to: Human Resources, Building Operations, and Information Services.

Because the last category of cost has the least direct relationship to capital projects, there needs to be a "test" to ensure that any function that allocates costs to capitalized overhead has some causal linkage with capital spending. This test is as follows:

"Would this function operate with fewer staff if the company ceased to undertake all capital projects?"

Methods:

The following methods should be used to determine the overhead capitalization allocation update:

Time estimation
In this method, the allocation factors (or " cost drivers") for a particular department or function are based on estimates of the proportion of time spent by employees within the department on activities in support of capital. These estimates are typically made by managers within the department who had a good knowledge and understanding of the workloads of associated employees.

Analysis of work planning software
In this method, outputs from Union work planning software are used to allocate the costs of certain management and support personnel within the operations areas of Union.

Volume drivers
In this method, allocations are based on measures of throughput for a particular department.

Composite ratios
In this method, allocation factors are based on the capitalization rates of other departments. This approach is used to allocate the costs of a number of support departments and activities (e.g. Human Resources).

Appendix B: Unregulated Allocation Settlement Rules

Unregulated costs include costs related to work in support of Union Gas unregulated storage, joint ventures and 3rd parties. As part of the budget process, all unregulated allocations should be updated based on the following guidelines:

Asset Based

Costs related to operating and maintaining the storage assets are allocated the same way the underlying asset is allocated. Administrative & general expenses are allocated in proportion to storage O&M. These allocations will be updated by the Team Lead O&M.

Project Development

O&M costs are allocated based on an estimate of time spent annually on the development of unregulated projects. Review these allocations with the key contacts in the Business Development, Engineering, Regulatory groups and any other groups that work on the development of unregulated projects and update the settlement if necessary.

Appendix C: FTE & Headcount

FTE

FTE is the equivalent full time roles that underpin your budget. For example, if you have one employee that fills a roll with a 37.5 hour standard work week then that employee is one FTE. You may substitute three employees and divide the 37.5 hours among these employees then those three employees would similarly be one FTE. You would budget the total salary and wages to be paid to the three non full time employees and budget one FTE. Assuming that the employees were of equivalent level you would budget the same dollars of salary and benefits regardless of the number of people working the 37.5 hours. **An individual can never be more than one full time equivalent even if they work and are paid for more than the standard number of work hours.** For example if an employee has a job with a standard work week of 37.5 hours but works 40 hours with overtime pay you would budget the total salary expected to be paid to the employee in the salary and the overtime PCE's and budget one FTE. Orion/Contract/Temp/Casuals must be included in the FTE count ONLY if they are accounted for in the Salaries & Wages budget for your area.

Headcount

Headcount is the number of actual employees working in a particular group regardless of hours worked.

strive higher

REVISED

2012 and 2013 Capital Budget Instructions

March 2, 2011

Strive Higher. For The Energy In You.

Budget Assumptions

- Detailed in SAP - 2012 and 2013 Maintenance Capital;
- High Level (not in SAP) – 2014 Maintenance Capital (details to follow)
- Interest During Construction (IDC) – 4.29% (2012 and 2013)
- USD Exchange – 1.00 USD = 1.019 CAD
- Salary & Wage Increase (Preliminary) – 2012 – 3.5%; 2013 – 4.0%; 2014 – 4.0%
- Leakage & DREAM Model – available on the Union Gas Portal site
- SAP version 50 (both years)
- Link to 2012 and 2013 Instructions and Documentation *(including: Instructions, WBS Elements, Component Listings; IFRS – Capital vs. O & M, SE Budget Categories): 2012 and 2013 Instructions & Documentation*
- Inflation – 2.1% (2012, 2013, 2014) for everything other than those listed in the “Inflation Indices

Inflation Indices

	2012
Steel Pipe	2.0%
Plastic Pipe	2.0%
Fittings	2.0%
Meter & Regulators	2.0%
Fleet Cost	2.1%
General Travel	2.1%
Contract Labour	3.2%
Tools	2.0%
Furniture	2.0%

	2013
Steel Pipe	1.8%
Plastic Pipe	1.8%
Fittings	1.8%
Meter & Regulators	1.8%
Fleet Cost	2.1%
General Travel	2.1%
Contract Labour	4.0%
Tools	1.8%
Furniture	1.8%

Consumer/Service Forecasts

2012 Customer/Service Forecast

	Consumers	Services
Windsor	1,036	806
Chatham	291	198
Sarnia	381	326
London	2,840	2,582
Brantford	934	785
Waterloo	3,843	3,355
Hamilton	2,656	1,989
Halton	3,513	3,302
Kingston	2,356	2,160
NW Thunder Bay	430	386
NW Timmins	175	118
NE Sudbury/SSM	1,030	923
NE Muskoka	895	802
Total	20,380	17,732

2013 Customer/Service Forecast

2013	Consumers	Services
Windsor	1,163	904
Chatham	323	220
Sarnia	420	359
London	3,138	2,852
Brantford	1,027	864
Waterloo	4,274	3,731
Hamilton	2,975	2,228
Halton	3,955	3,718
Kingston	2,606	2,390
NW Thunder Bay	455	408
NW Timmins	180	122
NE Sudbury/SSM	1,032	927
NE Muskoka	943	848
Total	22,491	19,571

CAPITAL PROJECT GUIDELINES

- <u>Capital Budget Template Instructions:</u>
- The capital budget requires detailing by the following categories in order to apply the proper loadings to the projects. DO NOT ADD LOADINGS TO YOUR COSTS.
    - Salary/Wages
    - Material
    - Other
- Capital Budget Upload Templates are posted on Sharepoint.
- See the template instructions within the template for complete details on how to populate the template.
- <u>NOTE:</u> IDC and loadings will be calculated within SAP on budgeted dollars. The loadings are currently being reviewed and may differ from the percentages on the template used in the 2010 Budget. You will need to reconcile your Plan with SAP once the loadings have been applied.

Guidelines - continued

All Projects

- **Templates –** When projects are created in SAP – templates reside in 11 (formerly 99 or 00) and must be used. (e.g. – 01-11-DAU, 22-11-DAO, 33-11-DAD) The correct loadings to be applied to the projects are within the new templates.
- NEW BUDGET CATEGORIES **–** will be available in SAP (drop down selection). You will be required to select the appropriate category when creating your project in SAP. Details to follow once available.
- Capital Projects that are being carried forward from one year to the next should use the same project number as past years even though it is identified with a project year other than 12 or 13.
- **Abandonment Costs** (costs of removing old plant) & Salvage Costs (amount received from the sale of the old plant) need to be planned in the 9000 WBS element series.
- **Reinstated:** WBS elements for groundbeds and rectifiers.

Guidelines - continued

- **Schedule 3's will not be required for routing purposes.** They should be prepared and kept locally and require the Project Submitter and the Project Sponsor to sign off on them. The Schedule 3's will need to be uploaded to the Sharepoint site as follows:
  - Risked Based Projects – April 8th
  - All other projects – April 30th
- The Schedule 3's need to be uploaded into the proper SE Budget Category Folders (e.g. Contractual, Economic Justification, In Franchise Growth, etc) **Please indicate the Budget Category on the Schedule 3**. Links to Sharepoint site for uploading Schedule 3's:
  - 2012 SE Budget Categories
  - 2013 SE Budget Categories

  - **Project Submitter** – responsible for the physical construction of facilities or purchase of assets and management of funds allocated for the project.
  - **Project Sponsor** (similar to Project Approver for requisitions) – responsible for the overall success of the project and refers to the head of the department that will be the most obvious beneficiary of the project.

Guidelines - continued

- **Cashflow** the project when the <u>work will be completed</u>. Use an appropriate method to arrive at the cashflow per month by considering:
  - Historical spending – can be used as a reference but remember you have different projects each year with different cashflow requirements;
  - Avoid dividing by 12 months;
  - Review the entire portfolio of work – can it all be done in the timing?

Guidelines - continued

- **Interest During Construction (IDC)** will need to be considered (IN SAP run ZPPMR029 – Allowance for funds used during construction plan). **Capital Reporting will run and attach the IDC report (from SAP) to the Schedule 3.** The following rules apply for considering IDC:
  - *Construction & Software Projects* meeting the following criteria:
    - *Projects > $1M* ***and***
    - *Construction period > 12 months*
    - *CWIP (construction work in progress) from previous year if the above criteria are met.*
  - *Exceptions:*
    - *Services (major & blanket)*
    - *Scattered mains*
    - *Scattered meter sets*
    - *Meter/regulator purchases*

Guidelines - continued

- Early Order Materials for 2012 Projects
  - This process is to facilitate the pre-ordering of long lead time items for known projects. The intent is that materials can be ordered in the Fall of 2011 for 2012 projects.
    - Budgetary dollars do not need to be included in the 2011 capital budget for 2012 construction projects.
    - A requisition will need to be created in order to have the materials ordered; however, the cashflow should not be started until January 2012.
    - The materials must be ordered late enough in 2011 so that they <u>are not</u> delivered until January 1, 2012.

Guidelines - continued

- CPREP Cost Estimating

  - Attached below is the link to the Replacement and New Business Pre-Work Checklists that will be used for your CPREP Cost Estimating in both 2012 and 2013.
  - The required Pre-work steps have been identified with ‘R’ (Required) in the checklist and with “O” (Optional) and “N/R” (Not Required) on the Pre-work form.
  - No site visits will be required for projects planned for 2013 that are < $200k.
  - Please refer to the CPREP Cost Estimating Checklists whenever you see CPREP cost estimates in this presentation. The Pre-Work form is the key document, with other tabs used as reference, when building the actual cost estimate.

Link to: CPREP Cost Estimating Checklist

Guidelines - continued

- <u>CAPITAL PROJECT NUMBERING:</u>

GROUP	# SEQUENCE	EXAMPLE
New Business Main Projects	300 - 499	01-11-301
Reinforcement Main Projects	500 – 599	04-11-520
Replacement Main Projects	600 – 699	07-11-600
Station Projects	700 – 799	16-11-711

Guidelines - continued

New Business Mains/Services/Meter & Regulator Blankets

- 2012 and 2013 Requirements:
- Budget to same level of detail as historical process.
- Assumptions based on forecast provided by Head Office.
- Schedule 3's – indicate the Budget Category.

Replacement Projects (General, Municipal, Leakage, Services)

- Specific general replacement projects <$200k are to be included in a Division blanket and not separately identified in SAP.
- General replacement blankets are to be budgeted in SAP Priority 7 – Replacements.
- Municipal projects <$500k are to be included in a Division Blanket and not separately identified in SAP
- Municipal projects/blankets are to be budgeted in SAP Priority C – Mains Municipal.
- The blanket amount will need to be supported and justified through specific projects, historical data, etc.

Guidelines - continued

- Replacement Projects (excluding blankets) > $200k must provide:
    - Asset details of the plant being replaced. For example – a station rebuild project would require an estimated percentage of the existing facility being retired.
    - Business Case, Leakage Model (if required), CPREP cost estimates and Risk Ranking; Please indicate Risk Ranking and Budget Category on Schedule 3.
- 2012 Requirements – General, Municipal, Leakage, Services:
    - One Schedule 3 per blanket with a list of each project planned as part of the blanket, Leakage Model for leakage projects.
    - Risk Ranking must be completed for all projects within the blanket.
- 2013 Requirements – General, Municipal, Leakage, Services;
    - One Schedule 3 per blanket with a list of each project planned as part of the blanket.
    - High level cost estimates for blankets (based on historical costs). <u>No risk rankings required at this time.</u>
    - Projects >$200k will require Schedule 3 with business case, Leakage Model (if required), CPREP cost estimates and risk ranking.

Guidelines - continued

- Major Projects
  - All projects > $200k are to be separately identified, supported and budgeted as such in SAP.
  - Only specific projects classified as New Business Major (>$200k) are to be budgeted in SAP Priority 4 – New Business – Major.
  - Only specific projects classified as Replacement Majors (>$200k) are to be budgeted in SAP Priority 9 – Replacement Majors.

  - 2012 Requirements:
    - Schedule 3 required for each project > $200k including full business case, Leakage Model (if required), Dream runs (if required), CPREP cost estimates and Risk Ranking (Replacement Majors);

  - 2013 Requirements:
    - Schedule 3 required for each project > $200k including full business case, Leakage Model (if required), Dream runs (if required), CPREP cost estimates and Risk Ranking (Replacement Majors);

Guidelines - continued

- Reinforcement Projects
  - ALL reinforcement budget dollars are to be identified as specific projects and set up as such in SAP.
  - There is to be no division blankets for reinforcement projects.

  - 2012 Requirements:
    - Schedule 3 required for each project (regardless of cost) including Business Case, CPREP cost estimates and Risk Ranking.
  - 2013 Requirements:
    - Schedule 3 required for each project (regardless of cost) including Business Case, cost estimates at a higher level. (e.g. Based on historic trends)
    - <u>No Risk Ranking required at this time</u>.

Guidelines - continued

Risk Based Category – includes projects that improve, upgrade or replace operating infrastructure and are subject to ranking based upon OMS risk analysis.

- Projects in this category include:
    - Leakage replacements
    - General Replacements and Major Replacement projects
    - Station Replacements
    - STO projects based on condition ie. RTU upgrades, turbine overhauls, lube oil systems etc.
- Risk Ranking (consequence driver and corresponding likelihood) must be identified on your Schedule 3.
    - One comprehensive financial schedule 3 may be completed for a blanket but <u>each</u> known project requires a separate project justification (Sch 3c) with risk ranking justification and leakage model if required.
- **Risk rank review meetings will take place between April 8th and 30th** . Any risk rank changes will be communicated with originator by April 30th. Review teams are as follows:
    - Distribution Station projects– <u>Jeff Falkiner</u>, Kevin Bowers, Charlie Higgins
    - Distribution Pipeline projects – <u>Scott Walker</u>, Kevin Bowers, Charlie Higgins
    - STO projects – <u>Jeff Falkiner</u>, Jim Harradine, Bob Wellington **(to take place the first week of May)**
- A follow up call will be scheduled to allow more discussion regarding risk ranking
- Please contact Denise Spadotto or risk rank review team members with any questions.

Capital budget categories

Budget Category	Description	Union Gas Examples
Regulatory / Code Compliance	Projects required to meet prescriptive regulatory requirements and all projects that Spectra has committed to a regulatory agency to complete under Goal Oriented / Performance Based regulations.	• Integrity • Certificate of Approval • Meter & regulator (replacements) • Odourant upgrades
Contractual	Projects that are required due to a binding non-revenue generating contract. Sample projects include Joint Venture Agreements, Long Wall Mining (US) and Municipal Replacements (Union).	• Municipal
Support Operations	Projects required to improve, upgrade or replace non-operating infrastructure (i.e. nothing directly attached to gas processing, gas compressors or the pipeline). These projects typically would not survive the risk ranking process, but are extremely important to the success of the business unit. Individual projects typically cost less than $50,000 but can exceed this with management approval.	• Tools • Roof/building upgrades & replacements • Telephone system replacements
Risk Based	Projects that improve, upgrade or replace operating infrastructure and are subject to ranking based upon risk analysis (probability and consequence).	• Leakage replacement • Replacements due to age & condition
Economic Justification	Projects that require an investment of Maintenance Capital dollars to either realize an O&M savings or generate incremental revenues which are not underwritten by a commercial contract. Hurdle rate requirements have not been established.	• Transportation replacements • New buildings
In Franchise Growth	Union Gas is required to connect customers that request service.	• New Business • Reinforcement
Overheads	Separated to meet Canadian accounting requirements.	• Overheads
AFUDC	Separated to meet Canadian accounting requirements.	• Does not apply to UG
Other	Projects that do not meet requirements for categories 1 – 8.	

Guidelines – (Head Office Support Groups – listed below, Engineering & STO)

Blanket Projects for Unspecified Capital Salary/Wages

- When a department's salary/wages and employee expenses are directly attributable to capital projects but the specific project has not been identified, blanket projects can be created in order to capture the capital plan. These will be "**planning only**" projects and the actuals costs will be charged to the specific projects identified during the year. Examples of departments with these blanket projects are: Engineering, Lands, Regulatory, Storage Planning and STO.

- Please use the following Project number for these projects:

Project Numbers

- Corrosion Eng–PLAN-Labour Expansion 37-XX-969
- Corrosion Eng–PLAN-Labour Maintenance 37-XX-964
- EDE Admin Eng–PLAN–Labour Expansion 37-XX-975
- EDE Admin Eng–PLAN–Labour Maintenance 37-XX-972
- Elect/Control Eng-PLAN-Labour Expansion 37-XX-977
- Elect/Control Eng-PLAN-Labour Maintenance 37-XX-974
- Lands – PLAN – Labour Expansion 37-XX-954
- Lands – PLAN – Labour Maintenance 37-XX-950
- Major Projects Eng–PLAN–Labour Expansion 37-XX-971
- Major Projects Eng-PLAN-Labour Maintenance 37-XX-970

Project Numbers

• Mapping/Drafting-PLAN-Labour Expansion	37-XX-967
• Mapping/Drafting-PLAN-Labour Maintenance	37-XX-962
• Measurement Eng-PLAN-Labour Expansion	37-XX-968
• Measurement Eng-PLAN-Labour Maintenance	37-XX-963
• Pipe/Const Eng-PLAN-Labour Expansion	37-XX-965
• Pipe/Const Eng-PLAN-Labour Maintenance	37-XX-960
• Procurement-PLAN-Labour Expansion	37-XX-980
• Regulatory-PLAN-Labour Expansion	37-XX-956
• Regulatory-PLAN-Labour Maintenance	37-XX-952

Project Numbers

- STO Eng-PLAN-Labour Expansion 37-XX-981
- STO Eng-PLAN-Labour Maintenance 37-XX-982
- Station Eng-PLAN-Labour Expansion 37-XX-966
- Station Eng-PLAN-Labour Maintenance 37-XX-961
- Stor Plang-PLAN-Labour Expansion 37-XX-957
- Stor Plang-PLAN-Labour Maintenance 37-XX-953
- System Planning Eng-PLAN-Labour Expansion 37-XX-976
- System Planning Eng-PLAN-Labour Maintenance 37-XX-973
- Welder/Fuser Eng-PLAN-Labour Expansion 37-XX-979
- Welder/Fuser Eng-PLAN-Labour Maintenance 37-XX-978

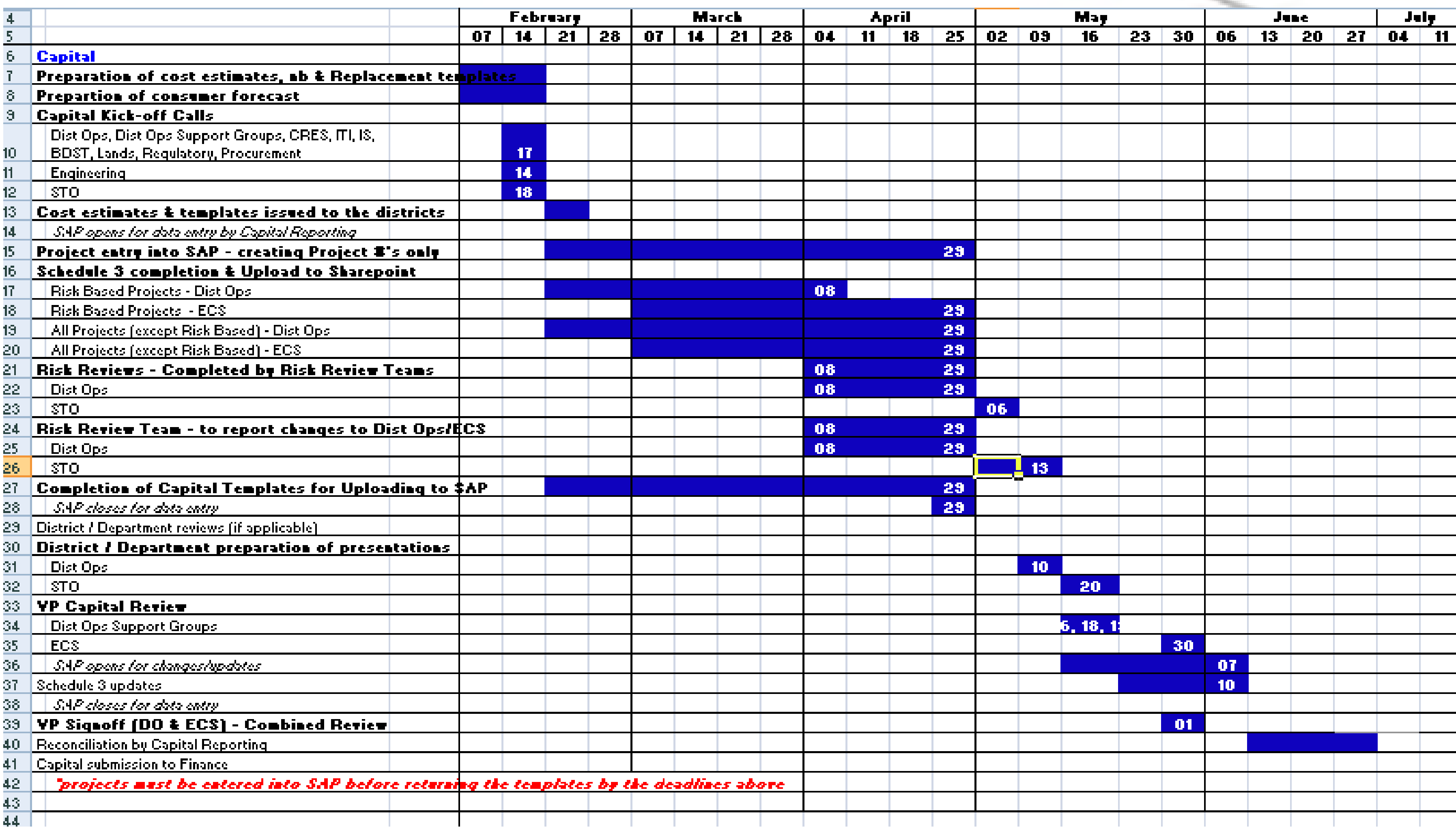
Regulated / Non-Regulated Projects

strive higher

- Separate non-regulated and regulated capital expenditures. For 100% non-regulated projects, use “800” series for project numbers as well as the non-regulated WBS elements 8XXX series. If possible, reserve the **“800” series** for 100% non-regulated projects.
- All other storage/Dawn projects need to have both regulated and non-regulated WBS elements included in the projects. <u>The planned dollars need to be allocated between regulated and non-regulated.</u> See Chart Below:

Facility	Regulated %	Non-Regulated %
Dawn Plant B	80.14%	19.86%
Dawn Plant C	80.14%	19.86%
Dawn Plant D	80.14%	19.86%
Dawn Plant E	100.00%	
Dawn Plant F	80.14%	19.86%
Dawn Plant G	80.14%	19.86%
Dawn Plant H	80.14%	19.86%
Dawn Plant I		100%
Dawn Plant J	57.55%	42.45%
All Union Gas owned Storage Pools (excluding Heritage Pool)	62.34%	37.66%
Heritage Pool		100%

Timeline


February March April May June July
07 14 21 28 07 14 21 28 04 11 18 25 02 09 16 23 30 06 13 20 27 04 11
Capital
Preparation of cost estimates, ab & Replacement templates
Prepartion of consumer forecast
Capital Kick-off Calls
Dist Ops, Dist Ops Support Groups, CRES, ITI, IS, BDST, Lands, Regulatory, Procurement
17
Engineering
14
STO
18
Cost estimates & templates issued to the districts
SAP opens for data entry by Capital Reporting
Project entry into SAP - creating Project #'s only
29
Schedule 3 completion & Upload to Sharepoint
Risk Based Projects - Dist Ops
08
Risk Based Projects - ECS
29
All Projects (except Risk Based) - Dist Ops
29
All Projects (except Risk Based) - ECS
29
Risk Reviews - Completed by Risk Review Teams
08 29
Dist Ops
08 29
STO
06
Risk Review Team - to report changes to Dist Ops/ECS
08 29
Dist Ops
08 29
STO
13
Completion of Capital Templates for Uploading to SAP
29
SAP closes for data entry
29
District / Department reviews (if applicable)
District / Department preparation of presentations
Dist Ops
10
STO
20
VP Capital Review
Dist Ops Support Groups
6, 18, 1
ECS
30
SAP opens for changes/updates
07
Schedule 3 updates
10
SAP closes for data entry
VP Signoff (DO & ECS) - Combined Review
01
Reconciliation by Capital Reporting
Capital submission to Finance
*projects must be entered into SAP before returning the templates by the deadlines above

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FOR THE ENERGY IN YOU

UNION GAS LIMITED

DESCRIPTION OF THE ECONOMIC FEASIBILITY TESTS

The purpose of this evidence is to describe the economic feasibility tests that Union applies to Union's capital additions.

The evidence is organized as follows:

1/ Three Stage Approach to Project Evaluations

2/ General Economic Feasibility Policies and E.B.O. 188 Guidelines

3/ Appendix A - Stage II and III for Project Evaluation

1/ THREE STAGE APPROACH TO PROJECT EVALUATIONS

The evidence on economic feasibility in this proceeding is based on the policies and methods previously approved by the Board. Union employs economic feasibility tests that are consistent and compliant with the Ontario Energy Board ("OEB") E.B.O. 134 Report on the Expansion of Natural Gas System in Ontario and the final report of the OEB pursuant to E.B.O. 188. Although the same three stage analysis approach outlined in E.B.0. 134 is used to assess major system expansion projects, the specific policies, practices and procedures and underlying test assumptions/parameters will vary depending on the nature of the project and the type of expansion being undertaken (i.e. transmission, distribution).

In a given year, Union evaluates all expansion projects for economic feasibility based on a number of decision factors such as profitability index ("PI") and net present value ("NPV").

Three Stage Analysis

Stage I

Stage I consists of a discounted cash flow ("DCF") analysis of the incremental cash inflows and outflows resulting from a project. The cash flows are discounted using the utility's incremental weighted average after tax cost of capital. Test results are presented as a ratio of the net present value of revenues (inflows) to the net present value of costs (outflows), referred to as the PI, and also the net present value of net revenues minus project costs, referred to as the total NPV.

Economics are evaluated over a period of time which normally corresponds with the useful life of the asset with the shortest life in the project, up to a maximum of forty (40) years. In cases where the capacity provided by the proposed facilities is designed exclusively to meet the needs of a single customer or small group of customers, the economics may be evaluated over a shorter period of time which takes into account the estimated time frame of the customer's commitment to natural gas. The majority of expansion projects undertaken are evaluated over a forty (40) year time horizon.

The cash inflows are estimated based on the incremental margins from sales and transportation service and other financial benefits to Union resulting from the construction of the additional facilities. The margin estimates are based on approved rates at the time the analysis is performed. The revenues are reduced by incremental operating and maintenance expenses, municipal taxes and income taxes, to arrive at the net incremental cash inflows.

Since Union undertakes many different expansion projects involving not only distribution but also market lines and Dawn-Parkway transmission facilities, it is important to ensure that benefits are not double counted. Union avoids any potential double counting of benefits through the application of various margins specific to the project application under review.

For most distribution projects, a margin specifically related to serving distribution facilities is used in the cash inflow calculation. If a project is related to the expansion of a market line, then a margin specifically related to the "other transmission" facilities is used. For Dawn-Parkway projects, a margin specific to those facilities is used.

The incremental cash outflows include the capital costs of the project facilities and other utility working capital requirements. The capital outflows include all incremental capital expenditures required for the provision of service by the proposed facility including the cost of materials, construction labour, land, land rights, environmental measures and direct overhead costs. General overheads are not included in the economic analysis as these costs would be incurred regardless of whether or not the project is undertaken.

If the Stage I NPV is greater than zero (i.e. PI greater than 1.0), it is presumed that the requirements of the Stage II test are also satisfied. However, for major system expansion projects, if the Stage I NPV is less than zero (i.e. PI less than 1.0), a Stage II and III benefit/cost analysis is undertaken to quantify certain other benefits and costs accruing to customers as a result of the project. See Appendix A for details of Stage II and Stage III analysis.

Long Term Dawn-Parkway Expansion

Union employs the three stage DCF analysis described earlier to evaluate Dawn-Parkway system expansions. A Stage I analysis is conducted for each incremental section of the Dawn-Parkway pipeline system. As the Dawn-Parkway System is a joint use facility, expansion results in benefits for all users of the system.

Distribution Expansion Projects

A general description of key aspects of the overall policy is outlined below. A more comprehensive description can be found at Exhibit B1, Tab 3, Appendix A under Distribution New Business Guidelines.

Distribution new business includes the extensions of gas service to both new customers who do not currently have access to natural gas in all market segments, as well as areas currently served by natural gas including new residential, multi-family and commercial/industrial developments and miscellaneous in-fill projects.

Union uses an Investment Portfolio approach based on forecast information and a 12-month historic Rolling Project Portfolio approach to manage the Stage 1 economics for all new business distribution expansion projects as described below.

2/ GENERAL ECONOMIC FEASIBILITY POLICIES AND EBO 188 GUIDELINES

In preparation of the budget for the years 2011, 2012 and 2013 Union used guidelines and policies that were developed in EBO 188, previous rate cases and facilities application as well as directives as provided by the Board from time to time.

Union's Investment Portfolio includes all forecasted projects necessary to attach any customer, regardless of class, in the forecast year. An annual Normalized Reinforcement Amount, as outlined in EBO 188, is added to the year's costs to minimize the impact of large reinforcements in any one year. The minimum Investment Portfolio PI is 1.0 but a PI of 1.10 target has been set as per OEB suggested guidelines to provide a safety margin to minimize adverse impacts resulting from forecast error.

The primary tool used for monitoring of the ongoing financial feasibility and rate impacts throughout the budget year is the Rolling Project Portfolio. This portfolio excludes infill customers but includes the Normalized Reinforcement Amount identified in the Investment

Portfolio. The minimum target for the Rolling Project Portfolio is a NPV of zero, which corresponds to a PI of 1.0.

Additional information regarding Union's policies is contained in Union's Distribution New Business Guidelines at Exhibit B1, Tab 3, Appendix A. This document outlines Union's practices concerning such items as customer connection and contributions, revenue horizons and minimum project PI.

3/ STAGE II AND III FOR PROJECT EVALUATION

Stage II

Stage II of the three-stage economic feasibility framework, analyzes the benefits and costs to Union's customers as a result of undertaking a proposed project. The benefits to customers are the quantifiable net energy cost savings that customers will realize by using natural gas service made possible by the project compared to alternative sources of energy supply. The cost to customers is the net cash flow deficiency resulting from the Stage I analysis. The Stage II benefits and costs are discounted using the social discount rate of 10% recommended by Board Staff in their 1992 discussion paper. The project is considered to be justified if the NPV of both the benefits and cost is greater than zero. In such cases, the quantifiable benefits related to the project exceed the quantifiable costs.

The Stage II analysis includes only those readily quantifiable direct costs and benefits associated with energy cost savings to Union incremental in-franchise customers. The net energy cost savings are quantified using estimated efficiency adjusted prices for alternative fuels and take into account the incremental capital costs of installing the natural gas heating equipment.

The total net benefits to the public can be understated in certain cases as the energy cost savings identified exclude any savings that would be realized by potential in-franchise Union contract customers and Ontario gas users outside of the franchise area. For some projects (i.e. the expansion of the Dawn-Parkway System), these unquantified benefits are likely to be as great as or greater than the estimated savings for Union's in-franchise customers.

Stage III

A Stage III analysis considers broader societal impacts to the province of Ontario that have not been included in the Stage I and Stage II tests. Examples of other quantifiable and non-quantifiable benefits/costs and other public interest considerations identified as part of the Stage III analysis include: additional employment, increased government taxes, increased disposable income, enhanced security of supply, system integrity and the environmental benefits of using a cleaner burning fuel.

In cases where a project relates to a joint-use facility that will benefit all customers served, greater emphasis may be placed on the positive societal benefits identified at Stage III of the economic analysis in the assessment of whether or not a project should proceed.

UNION GAS LIMITED

CHANGES IN POLICIES, PROCEDURES AND METHODOLOGIES

Since the EB-2005-0520 proceeding, Union has made the following changes in policies, procedures and methodologies that have impacted regulatory expenses.

CONVERSION TO US GAAP

In 2008, the Accounting Standards Board ("AcSB") of the Canadian Institute of Chartered Accountants ("CICA") announced that publicly accountable enterprises are required to adopt International Financial Reporting Standards ("IFRS") in place of Canadian Generally Accepted Accounting Principles ("CGAAP") for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011.

In September 2010, the AcSB offered an optional one-year deferral for adopting IFRS for qualifying entities with rate-regulated activities and permitted such entities to continue to apply the pre-changeover accounting standards of the CICA Handbook during that period. Union is a qualifying entity for purposes of the one-year deferral and elected to defer the adoption of IFRS to review the option to report under United States Generally Accepted Accounting Principles ("US GAAP").

IFRS currently does not adequately provide for accounting for rate-regulated activities. Adoption of IFRS by Union would create significant uncertainty in its financial reporting and have a substantial impact on its financial results at the time of adoption. The anticipated impact to Union of the adoption of IFRS is a substantial retained earnings loss and ongoing income statement volatility and uncertainty. IFRS would not transparently reflect the actual economic effects of rate regulation.

US GAAP provides a well-recognized, accepted and comprehensive basis of accounting for rate-regulated activities that is substantially similar to CGAAP and will provide Union with consistency that reflects the economic realities of these activities.

The adoption of US GAAP by Union would avoid the current uncertainty about the application of IFRS to rate-regulated activities, including uncertainty concerning the substantial one-time adjustments and implementation issues upon adoption and any possible future adjustments to IFRS to address rate-regulated activities.

In 2011, Canadian security regulators approved Union's election to report under US GAAP instead of IFRS effective January 1, 2012. To be consistent with financial reporting, Union is proposing to adopt US GAAP for rate making.

The differences between CGAAP and US GAAP are far less than the differences that would have existed had Union adopted IFRS. The only impact to utility earnings as a result of reporting under US GAAP is to the employee future benefits expense.

Employee Future Benefits Expense

The US GAAP standard for reporting on pension and post-retirement benefit costs (ASC 715 *Compensation – Retirement Benefits*) results in a different expense than the Canadian GAAP standard (CICA 3461 *Employee Future Benefits*) currently used by Union.

The employee future benefits expense for US GAAP is different than CGAAP for two reasons: the change in measurement date from September 30 to December 31, and the amortization of unrecognized actuarial losses that were established upon the implementation of CICA 3461. At the time of transition to CICA 3461, unrecognized actuarial losses were established and amortized over the expected average remaining service life of the plan employees at that time. These unrecognized actuarial losses would have been fully amortized under US GAAP.

Union requested a deferral account in EB-2011-0025 for the amount recognized in retained earnings associated with transitioning accounting standards and reporting to US GAAP for previously unrecorded pension and post-retirement expenses. The amount to be recorded in this account represents the impact of converting to US GAAP. In 2012, Union proposes to amortize an amount to adjust employee future benefits cost to the CGAAP equivalent to reflect the approach used to set rates.

Union will address the disposition of the remaining balance of the proposed deferral account (179-127 Pension Charge on Transition to US GAAP) in the 2012 annual deferral disposition proceeding.

The employee future benefits expense presented in the 2013 test year forecast and discussed at Exhibit D1 Tab 3 is based on US GAAP without any additional amortization of the proposed deferral account.

ALLOCATION OF INDIRECT OVERHEADS COSTS

In 2010, Union changed its methodology for allocating indirect overhead costs ("OH") to capital assets.

After completing work on the IFRS conversion project, Union determined that OH costs are capital within a regulatory environment, but are expensed in an unregulated environment. As a result, subsequent to 2010, OH was no longer distributed to individual assets but capitalized to a single asset per functional category as Regulatory Overhead Assets. Regulatory Overhead Assets are amortized over the average life of the assets within each functional category that attracts overheads. Costs that can be allocated to individual assets are done so through a direct charge with those assets attracting direct overheads through a loading based on employee hours directly charged to the assets. Previous to 2010, individual assets did not attract direct overheads in this manner but through the OH allocation.

Although Union is no longer adopting IFRS, it opted to continue to use this methodology.

The change in methodology of no longer distributing OH to individual assets has no impact on utility earnings or rate base.

ACCOUNTING FOR LINE PACK GAS

In 2010, Union reclassified line pack gas ("LPG") from gas in inventory to property, plant and equipment.

The main purpose of LPG is to be kept within the Company's transmission pipelines to maintain a certain minimum pressure thereby facilitating the flow of gas to Union's customers. LPG is made up of two components: base LPG and working LPG. Base LPG represents the minimum level required to remain in the transmission pipelines whereas working LPG is available for sale and is comprised of any remaining portion over-and-above base LPG.

Base LPG is not available for sale to customers and is therefore considered capital in nature. Capital assets are not revalued quarterly but remain recorded at historical cost.

Consistent with the change in accounting classification and for administrative simplicity, Union is proposing that LPG should not be revalued quarterly as a part of inventory. This requires a change in the accounting order 179-109 to remove the LPG account from the quarterly revaluation process.

Union does not expect any material impact to utility earnings as a result of changing the accounting for base LPG.

PREFILED PRODUCTIVITY EVIDENCE OF

DAVID RICHARDS, MANAGER, GOVERNANCE & REPORTING

INTRODUCTION

The purpose of this evidence is to provide information regarding Union Gas Limited's ("Union") productivity initiatives undertaken during the incentive regulation period. This evidence is organized under the following headings:

1/ Productivity Background

2/ Cost Savings and Incremental Revenue Generation Overview (2008-2011)

3/ Operating and Maintenance ("O&M") and Capital Cost Savings

4/ Incremental Revenue Generation

1/ PRODUCTIVITY BACKGROUND

Throughout the incentive regulation period Union collected data to quantify the cost savings and incremental revenue associated with various productivity initiatives. Results are often estimates of cost savings calculated by comparing projected costs to that which would have been incurred had specific savings initiatives not been undertaken. In some cases, incremental revenues for certain initiatives were easily identifiable while in other cases, it was difficult to isolate the incremental revenue associated with a particular initiative.

In determining what qualified as "productivity", the following criteria were applied:

i. Opportunity must be sustainable over multiple periods and not a one-time exercise; and,
ii. Must result in cost savings or incremental revenue generation related to "productivity".

The initiatives described in this evidence pertain to Union's regulated business. The cost savings or incremental revenue generation discussed in this evidence are considered sustainable year over year unless noted otherwise. For some initiatives, the magnitude of the cost savings or incremental revenues may vary annually. Additional information is provided below and in Exhibit A2, Tab 5, Appendix A, for initiatives generating in excess of $1.0 million in combined annual cost savings or incremental revenue generation.

2/ COST SAVINGS AND INCREMENTAL REVENUE GENERATION OVERVIEW (2008-2011)

Table 1 summarizes total productivity cost savings and incremental revenue generation from 2008 to 2011 for Union's regulated activities.

Table 1
Total Cost Savings and Incremental Revenue Generation

Line No.	Category ($ millions)	2008	2009	2010	2011
1	O&M	2.8	12.5	16.0	15.5
2	Capital	0.1	1.9	9.7	10.8
3	Revenue	5.4	14.9	16.1	26.1
4	Total	8.3	29.3	41.8	52.4

At the end of 2011, the total cost savings and incremental revenue generation were $52.4 million.

The following is a description of the key productivity initiatives that provide cost savings or incremental revenue generation of $1.0 million or more annually.

3/ O&M AND CAPITAL COST SAVINGS

O&M cost savings related to productivity initiatives have been realized since 2008. At the end of 2011, the O&M cost savings in Table 2 were $15.5 million.

Capital cost savings related to productivity have been realized since 2008 as indicated in Table 3. At the end of 2011, the capital cost savings in Table 3 were $10.8 million.

Table 2
O&M Initiatives: Cost Savings
Showing Individual Initiatives > $1.0 Million

Line No.	Initiative ($ millions)	2008	2009	2010	2011
1	Sales and Marketing Realignment	0.4	2.7	3.2	3.4
2	Field Work Effectiveness	0.4	2.2	3.2	3.2
3	Wireless Voice Modernization Project	-	0.1	0.9	1.3
4	Employee Spending	0.8	2.3	1.4	-
5	IT Governance/Demand Management	0.1	0.5	0.9	0.9
6	Other (74 initiatives < $ 1.0 million each)	1.1	4.7	6.4	6.7
7	Total	2.8	12.5	16.0	15.5

Table 3
Capital Initiatives: Cost Savings
Showing Individual Initiatives > $1.0 Million

Line No.	Initiative ($ millions)	2008	2009	2010	2011
1	Construction Planning, Reporting & Execution Process	-	-	4.7	7.0
2	IT Governance/Demand Management	0.1	0.7	1.3	1.3
3	Field Work Effectiveness	-	0.5	0.9	0.9
4	Major Projects Design Work	-	-	2.0	0.5
5	Wireless Voice Modernization Project	-	0.4	0.4	0.5
6	Other (6 initiatives < $ 1.0 million each)	-	0.3	0.4	0.6
7	Total	0.1	1.9	9.7	10.8

Below is a summary of individual O&M and capital productivity initiatives contributing to cost savings in excess of $1.0 million annually.

3.1/ Sales and Marketing Realignment

A review of Union's sales and marketing processes found inefficiencies in Union's approach to general service sales and marketing efforts. In order to utilize its resources more efficiently, Union reorganized and reduced the number of employees in its general service marketing department and refocused efforts to include the promotion of self-service transactional choices to customers. As a result, Union reduced costs in its general service marketing and customer care areas while maintaining its commitment to adding new general service customers.

At the end of 2011, the O&M cost savings were $3.4 million.

3.2/ Field Work Effectiveness

This initiative was designed to improve the overall effectiveness of field employees in Union's Distribution Operations area. Field Work "Effectiveness" incorporated components of safety, quality and efficiency across the entire work cycle including:

i. Efficiency gains achieved through increased time availability of field work time due to improvements in work planning, training, process improvements and reporting metrics; and,
ii. Quality improvements realized through policy reviews and process changes reducing rework and multiple site visits.

Savings were achieved through a combination of process changes designed to drive efficiencies. Enhanced monitoring and target setting has been implemented to ensure a consistent focus on outcomes across all divisions. Targets and performance are continually monitored and adjusted to ensure optimal use of Union's work resources remain the focus. This initiative has both an O&M and capital savings component.

At end of 2011, the O&M cost savings were $3.2 million.

At end of 2011, the Capital cost savings were $0.9 million.

3.3/ Wireless Voice Modernization Project

This initiative began in 2009 by conducting a comprehensive internal review to look at improving the use of technology and equipment in lieu of a simple replacement of aging systems. The goal of this initiative was to eliminate redundant voice and data technology and replace it with more modern and cost effective technology solutions. These changes in technology and processes resulted in ongoing annual cost savings. This initiative has both an O&M and capital cost savings component.

At the end of 2011, the O&M cost savings were $1.3 million.

At the end of 2011, the capital cost savings were $0.5 million.

3.4/ Employee Spending

This initiative was designed to identify, develop, communicate, and implement business policies and practices that influenced behaviour resulting in O&M cost savings.

The scope included the following cost types:

i. Corporate travel including transportation (air, train, taxis, car rentals), mileage reimbursement, accommodations, and meals;
ii. Training & conferences;
iii. Telecommunications (cell phones, Blackberry's, pagers);

iv. Promotional items; and,
v. Office supplies.

The O&M cost savings from this initiative were determined by comparing actual spending levels in the above categories to spending levels in 2007. The goal was to hold overall corporate spending in these categories flat to 2007 levels by implementing and reinforcing a variety of behaviours that raised awareness and optimized controllable spending across the organization. Examples of these behavioural changes cover a broad spectrum including:

i. Greater use of technology (on-line meetings, web cameras) in lieu of face to face off-site meetings;
ii. Continual focus on minimizing the number of meetings requiring significant travel;
iii. Centralized and consistent booking of travel through corporate travel provider;
iv. Effective use of cell phones (optimizing packages available, increased knowledge of how to minimize roaming and other types of charges);
v. Encouraging car pooling;
vi. Providing tools to determine at what point it is less expensive to rent vs. drive your own vehicle; and,
vii. Encouraging less printing and utilization of duplex printing options when available.

Due to cost increases, primarily in employee training and travel expenses (e.g. air travel), Union was not able to maintain the 2007 employee spending amount beyond 2011.

3.5/ Information Technology Governance/Demand Management

This initiative assists in prioritizing Information Technology ("IT") resources to ensure they are focused on those projects providing the greatest value to Union. By implementing a more rigorous process for assessing IT enhancements and activities, return on investment for these initiatives can be increased. An IT Capital Steering Committee has been formed to review and ensure that the highest value projects are prioritized and resourced in alignment with Union's business priorities. The savings generated are a direct result of implementing a better upfront screening approach for IT initiatives and reducing the overall amount of work and resources required. This initiative has both an O&M and Capital cost savings component.

At the end of 2011, the O&M cost savings were $0.9 million.

At the end of 2011, the Capital cost savings were $1.3 million.

3.6/ Construction Planning, Reporting & Execution Process ("C-PREP")

This initiative developed common construction processes, practices and procedures for Distribution Operations across all Union districts. The C-PREP team included representatives from different disciplines and geographic areas across Union's franchise and from Union's construction Alliance partners (Aecon and Linkline). The team created a process to examine existing practices, identify gaps, and develop best practices and consistent processes and procedures. They also developed project tracking, key performance indicators, and financial reporting improvements to monitor the savings realized and costs avoided. In addition to the development of these construction project management processes, comprehensive training and quality assurance programs were developed to monitor progress and ensure the new processes deliver expected results.

Savings were generated through process improvement and reducing the amount of maintenance capital spent on municipal replacements by having the ability to influence the scope of a project or eliminating it all together.

At the end of 2011, the capital cost savings in Table 3 were $7.0 million.

3.7/ Major Projects Design Work

Major projects design work is an initiative that reviewed and streamlined the design process for major engineering projects. This initiative reviewed the cost and use of outside resources for project design and related work. The outcome of this initiative was to optimize cost savings by rebalancing outsourced vs. in-house work. As a result, less work was outsourced allowing for savings due to lower costs of doing this work internally. At peak times, outsourcing would be increased for the major projects as required to supplement the work done in-house and/or to free up in-house resources in order to focus on work of higher value. The amount of savings fluctuates from year to year dependent upon both the number of major projects in progress and the size of the effort from which savings can be realized.

At the end of 2011, the Capital cost savings were $0.5 million.

4/ Incremental Revenue Generation

Incremental revenues related to productivity initiatives have been realized since 2008 as indicated in Table 4. At the end of 2011, the incremental revenues generated were $26.1 million.

Table 4
Revenue Initiatives: Incremental Revenue Generation
Showing Individual Initiatives > $1.0 Million

Line No.	Initiative ($ millions)	2008	2009	2010	2011
1	Upstream Transportation	5.0	14.0	11.7	22.0
2	Dawn to Parkway Optimization	-	-	3.0	3.0
3	Other (4 initiatives < $ 1.0 million each)	0.4	0.9	1.4	1.1
4	Total	5.4	14.9	16.1	26.1

Below is a summary of individual initiatives contributing to incremental revenues in excess of $1.0 million annually.

4.1/ Upstream Transportation

This initiative involved using pipeline incentive programs (TransCanada Pipelines' Firm Transportation Risk Alleviation Mechanism) to generate incremental revenues. The services for ratepayers were not impacted. The results of this initiative are included in S&T Exchange revenue (as outlined in Exhibit C1, Tab 3).

At the end of 2011, the incremental revenue generated was $22.0 million.

4.2/ Dawn to Parkway Optimization

This initiative reviewed opportunities to generate additional revenue from Union's Dawn to Parkway transmission system. Through analysis of historical data, Union was able to obtain more detailed information on how customers use the Dawn to Parkway system. Union was able to use this detailed information to identify new optimization opportunities which resulted in incremental revenue.

At the end of 2011, the incremental revenue generated was $3.0 million.

Sales and Marketing Realignment

Project Overview

Business Area: Marketing and Customer Care

Productivity Category: O&M cost savings

Project Description:
A review of Union's sales and marketing processes found inefficiencies in Union's approach to general service sales and marketing efforts. In order to utilize its resources more efficiently, Union reorganized and reduced the number of employees in its general service marketing department and refocused efforts to include the promotion of self-service transactional choices to customers. As a result, Union reduced costs in its general service marketing and customer care areas while maintaining its commitment to adding new general service customers.

Key Assumptions:

i. Adjustments in organizational structure and roles occur in a timely fashion;
ii. HR support will be critical through both organizational design and staffing phase;
iii. Leverage appointment process to accelerate staffing process; and,
iv. Coordinated corporate communications plan and support is conducted.

Key Risks:

i. Adjustment in organizational structure and roles takes longer than anticipated eroding potential project benefits.

Cost Savings/Incremental Revenue Generation ($ millions):

	Notes	2008	2009	2010	2011
O&M Savings		0.416	2.722	3.170	3.382
Capital Savings					
Revenue Generation					
TOTAL		**0.416**	**2.722**	**3.170**	**3.382**

Field Work Effectiveness

Project Overview

Business Area: Distribution Operations

Productivity Category: O&M cost savings, capital cost savings

Project Description:
This initiative was designed to improve the overall effectiveness of field employees in Union's Distribution Operations area. Field Work "Effectiveness" incorporated components of safety, quality and efficiency across the entire work cycle including:

i. Efficiency gains achieved through increased time availability of field work time due to improvements in work planning, training, process improvements and reporting metrics; and,
ii. Quality improvements realized through policy reviews and process changes reducing rework and multiple site visits.

Savings were achieved through a combination of processes changes designed to drive efficiencies. Enhanced monitoring and target setting has been implemented to ensure a consistent focus on outcomes across all divisions in the company. Targets and performance are continually monitored and adjusted to ensure optimal use of Union's work resources remain the focus.

Key Assumptions:

i. Work tasks can be measured in order to support comparisons of actual time spent working to that planned;
ii. Savings can be delivered while the geography can still be supported by the remaining workers and the capability of the organization maintained;
iii. Any reduction in work force would occur through natural attrition– wholesale severances would reduce the savings;
iv. Changes to working practices can be made within reasonable time limits; and,
v. The organization has the collective will to advance this opportunity organization-wide.

Key Risks:

i. Benefits cannot be realized owing to geographical/capability issues and the ability to remove positions without severance costs;

ii. Could see some resistance if change management not handled appropriately; and,

iii. Data is not clean enough to support automated reporting. Manual reporting is not feasible for this initiative.

Cost Savings/Incremental Revenue Generation ($ millions):

	Notes	**2008**	**2009**	**2010**	**2011**
O&M Savings		0.400	2.200	3.175	3.175
Capital Savings			0.482	0.900	0.900
Revenue Generation					
TOTAL		**0.400**	**2.682**	**4.075**	**4.075**

Wireless Voice Modernization Project

Project Overview

Business Area: Information Technology

Productivity Category: O&M cost savings, capital cost savings

Project Description:
This initiative began in 2009 by conducting a comprehensive internal review to look at improving the use of technology and equipment in lieu of a simple replacement of aging systems. The goal of this initiative was to eliminate redundant voice and data technology and replace it with more modern and cost effective technology solutions. These changes in technology and processes resulted in ongoing annual cost savings.

Key Assumptions:

i. Users will experience improved reliability of the data network by switching to public cellular network;
ii. All users (approximately 400) to be provided new laptops and cell phones as part of converting all communications over to public network; and,
iii. Dismantling of communications towers to be managed as a separate initiative.

Key Risks:

i. Cellular coverage from public networks sufficient to provide service to all locations/employees; and,
ii. Pilot of APN (private network technology) may not be able to provide connectivity and security required by work management application.

Cost Savings/Incremental Revenue Generation ($ millions):

	Notes	2008	2009	2010	2011
O&M Savings			0.125	0.903	1.250
Capital Savings			0.350	0.400	0.500
Revenue Generation					
TOTAL			**0.475**	**1.303**	**1.750**

Employee Spending

Project Overview

Business Area: All Areas

Productivity Category: O&M cost savings

Project Description:
This initiative was designed to identify, develop, communicate, and implement business policies and practices that influenced behaviour resulting in O&M cost savings.

The scope included the following cost types:

i. Corporate travel including transportation (air, train, taxis, car rentals), mileage reimbursement, accommodations, and meals;
ii. Training & conferences;
iii. Telecommunications (cell phones, Blackberry's, pagers);
iv. Promotional items; and,
v. Office supplies.

The O&M cost savings from this initiative were determined by comparing actual spending levels in the above categories to spending levels in 2007. The goal was to hold overall corporate spending in these categories flat to 2007 levels by implementing and reinforcing a variety of behaviours that raised awareness and optimized controllable spending across the organization. Examples of these behavioural changes cover a broad spectrum including:

i. Greater use of technology (on-line meetings, web cameras) in lieu of face to face off-site meetings;
ii. Continual focus on minimizing the number of meetings requiring significant travel;
iii. Centralized and consistent booking of travel through corporate travel provider;
iv. Effective use of cell phones (optimizing packages available, increased knowledge of how to minimize roaming and other types of charges);
v. Encouraging car pooling;
vi. Providing tools to determine at what point it is less expensive to rent vs. drive your own vehicle; and,
vii. Encouraging less printing and utilization of duplex printing options when available.

Key Assumptions:

i. Managers have accountability for the amount of employee expenses generated in their departments.

Key Risks:

i. Lack of clearly defined employee expense policies;
ii. Inconsistent adherence to and application of employee expense policies across departments;
iii. Lack of clearly defined accountabilities on management to actively track and manage employee expenses;
iv. Lack of executive sponsorship; and,
v. Inability to hold flat to 2007 spending levels for the relevant cost types.

Cost Savings/Incremental Revenue Generation ($ millions):

	Notes	**2008**	**2009**	**2010**	**2011**
O&M Savings	1	0.806	2.340	1.362	
Capital Savings					
Revenue Generation					
TOTAL		**0.806**	**2.340**	**1.362**	

Notes to Chart:

1. Due to cost increases, Union was not able to maintain the 2007 employee spending amount beyond 2011.

IT Governance/Demand Management

Project Overview

Business Area: Information Technology

Productivity Category: O&M cost savings, capital cost savings

Project Description:
This initiative assists in prioritizing Information Technology ("IT") resources to ensure they are focused on those projects providing the greatest value to the company. By implementing a more rigorous process for assessing IT enhancements and activities, return on investment for these initiatives can be increased. An IT Capital Steering Committee has been formed to review and ensure that the highest value projects are prioritized and resourced in alignment with Union's business priorities. The savings generated are a direct result of implementing a better upfront screening approach for IT initiatives and reducing the overall amount of work and resources required. This initiative has both an O&M and Capital cost savings component.

Key Assumptions:
i. Achieving this opportunity will require some organization, process and governance changes, particularly within the Information Services ("IS") area;
ii. This proposal has a significant impact on how the business units interact with IS and will require some changes to the culture at Union to be successful; and,
iii. Fewer requests will be reviewed and considered given the requirement to go through an executive review.

Key Risks:
i. IS is not able to more actively monitor staff skills and availability; and,
ii. Not able to realize a reductions in management time from fewer enhancements.

Cost Savings/Incremental Revenue Generation ($ millions):

	Notes	2008	2009	2010	2011
O&M Savings		0.050	0.458	0.875	0.865
Capital Savings		0.050	0.680	1.277	1.277
Revenue Generation					
TOTAL		**0.100**	**1.138**	**2.152**	**2.142**

Construction Planning, Reporting & Execution Process ("C-PREP")

Project Overview

Business Area: Distribution Operations

Productivity Category: Capital cost savings

Project Description:
This initiative developed common construction processes, practices and procedures for Distribution Operations across all Union districts. The C-PREP team included representatives from different disciplines and geographic areas across Union's franchise and from Union's construction Alliance partners (Aecon and Linkline). The team created a process to examine existing practices, identify gaps, and develop best practices and consistent processes and procedures. They also developed project tracking, key performance indicators, and financial reporting improvements to monitor the savings realized and costs avoided. In addition to the development of these construction project management processes, comprehensive training and quality assurance programs were developed to monitor progress and ensure the new processes deliver expected results.

Savings were generated through process improvement and reducing the amount of maintenance capital spent on municipal replacements by having the ability to influence the scope of a project or eliminating it all together.

Key Assumptions:

i. All Union Gas districts and Alliance partners are full participants;
ii. Common set of standard process and procedure documentation is developed for each role within the construction group; and,
iii. Financial reporting structure is put in place to support high performance key performance indicators to be used across the franchise.

Key Risks:

i. Change management challenges delay or erode project benefits realized; and,
ii. Key performance indicators are not able to be monitored as planned.

Cost Savings/Incremental Revenue Generation ($ millions):

	Notes	2008	2009	2010	2011
O&M Savings					
Capital Savings				4.670	7.036
Revenue Generation					
TOTAL				**4.670**	**7.036**

Major Projects Design Work

Project Overview

Business Area: Engineering, Construction and Storage and Transmission Operations

Productivity Category: Capital cost savings

Project Description:
Major projects design work is an initiative that reviewed and streamlined the design process for major engineering projects. This initiative reviewed the cost and use of outside resources for project design and related work. The outcome of this initiative was to optimize cost savings by rebalancing outsourced vs. in-house work. As a result, less work was outsourced allowing for company savings due to lower costs of doing this work internally. At peak times, outsourcing would be increased for the major projects as required to supplement the work done in-house and/or to free up in-house resources in order to focus on work of higher value. The amount of savings fluctuates from year to year dependent upon both the number of major projects in progress and the size of the effort from which savings can be realized.

Key Assumptions:

i. Sufficient internal resources are available to realize in-house savings; and,
ii. There is a continual supply of projects and opportunities from which to generate savings.

Key Risks:

i. Savings are not realized due to low project activity, smaller effort projects, internal resource constraints, or some combination of these.

Cost Savings/Incremental Revenue Generation ($ millions):

	Notes	2008	2009	2010	2011
O&M Savings					
Capital Savings				2.000	0.505
Revenue Generation					
TOTAL				**2.000**	**0.505**

Upstream Transportation

Project Overview

Business Area: Business Development, Storage & Transmission

Productivity Category: Incremental Revenue generation.

Project Description:
This initiative involved using pipeline incentive programs to generate incremental revenues (TCPL's FTRAM). The services for ratepayers were not impacted. The results of this initiative are included in S&T Exchange revenue (as outlined in Exhibit C1, Tab 3).

Key Assumptions:
i. Services for rate payers are not impacted; and,
ii. There is sufficient market demand and capacity available to provide the service.

Key Risks:
i. The continuation of the FTRAM program to generate and sustain revenues.

Cost Savings/Incremental Revenue Generation ($ millions):

	Notes	2008	2009	2010	2011
O&M Savings					
Capital Savings					
Revenue Generation		4,968	14,048	11,704	20.004
TOTAL		**4,968**	**14,048**	**11,704**	**20.004**

Dawn to Parkway Optimization Project

Project Overview

Business Area: Business Development, Storage & Transmission

Productivity Category: Incremental Revenue generation.

Project Description:
This initiative reviewed opportunities to generate additional revenue from Union's Dawn to Parkway transmission system. Through analysis of historical data, Union was able to obtain more detailed information on how customers use the Dawn to Parkway system. Union was able to use this detailed information to identify new optimization opportunities which resulted in incremental revenue.

Key Assumptions:

i. Reporting tools available operating effectively; and,
ii. Sufficient market demand for Dawn to Parkway transportation service.

Key Risks:

i. Dawn to Parkway demands are higher than expected; and,
ii. Cost to purchase backstopping services on a peak winter day.

Cost Savings/Incremental Revenue Generation ($ millions):

	Notes	2008	2009	2010	2011
O&M Savings					
Capital Savings					
Revenue Generation				3.020	3.020
TOTAL				**3.020**	**3.020**

UNION GAS LIMITED
Financial Summary including Derivation of Revenue Deficiency/Sufficiency

Line No.	Particulars	EB-2011-0210 Proposed (a)	EB-2005-0520 Approved (b)	
1	Test Year	Calendar 2013	Calendar 2007	
2	Rate Base ($000s)	3,741,542	3,270,894	
3	Requested return	291,851	259,490	
4	Requested rate of return on rate base	7.80%	7.93%	
5	Total operating revenue ($000s)	1,598,544	1,966,854	
6	Total throughput volumes (10^3m^3)	14,221,290	14,526,151	
7	Capital Expenditures ($000s)	371,702	312,965	
8	Total customers	1,399,591	1,298,985	
9	Total Cost of Service ($000s) (see page 2)	1,651,159	1,977,930	/u

UNION GAS LIMITED
Financial Summary including Derivation of Revenue Deficiency/Sufficiency

Line No.	Particulars	EB-2011-0210 Proposed (a)	EB-2005-0520 Approved (b)	
	Operating Revenues: ($000s)			
1	Gas Sales	1,401,869	1,796,757	
2	Transportation	162,055	127,701	
3	Storage	11,488	17,962	
4	Other	23,132	24,434	
5	Earnings sharing	-		
6	Total Operating Revenue	1,598,544	1,966,854	
	Operating Expenses: ($000s)			
7	Cost of gas	697,838	1,135,825	/u
8	Operating and maintenance expenses	393,228	326,222	/u
9	Depreciation	196,467	173,780	
10	Other financing	1,179	315	
11	Property and capital taxes	64,022	67,709	
12	Income taxes	6,574	14,589	/u
13	Return	291,851	259,490	
14	Total Cost of Service including Return	1,651,159	1,977,930	/u
15	Revenue Deficiency/(Sufficiency) after tax	52,615	11,076	/u
16	Provision for income taxes on deficiency (sufficiency)	18,009	6,263	/u
17	Total revenue deficiency/(sufficiency)	70,625	17,339	/u
18	Long-term storage premium subsidy	-	(19,265)	
	Shareholder portion of transactional S&T margin:			
19	Short-term storage & balancing services	754	1,583	/u
20	Transportation & exchanges and other S&T services	-	343	
21	Adjusted revenue deficiency/(sufficiency)	71,378	-	/u
	Requested Rate of Return:			
22	Long-term debt	3.93%	4.72%	
23	Short-term debt	(0.04%)	(0.01%)	
24	Total debt	3.89%	4.71%	
25	Preference Shares	0.08%	0.15%	
26	Common Equity	3.83%	3.07%	
27	Overall	7.80%	7.93%	
	Cost of Capital:			
28	Long-term debt	6.50%	7.66%	
29	Short-term debt	1.31%	1.58%	
30	Preference Shares	3.05%	4.74%	
31	Common Equity	9.58%	8.54%	

UNION GAS LIMITED
Revenue Deficiency/Sufficiency Components (Weather Normalized)
2013 Proposed vs. 2007 Board-Approved

Line. No.	Particulars ($ millions)	Impact		Evidence Reference	
		(a)	(b)	(c)	
	Revenue:				
1	Contract Market	7		(Exh. C1/Sum Sch 4/Line 23+Line 28)	
2	General Service Market	(13)		(Exh. C1/Sum Sch 4/Line 5)	
3	S&T[1]	(10)		(Exh. C1/Sum Sch 5/Line13)	/u
4	Other Revenue	1		(Exh. C1/Sum Sch 6/Line 6)	
5	Sub Total: Net Revenue	(15)			/u
6	Delivery-related Gas Costs:	(37)		(Exh. H3/T1/Sch 4)	/u
	O&M:				
7	Compensation	59		(Exh. D1/Sum Sch 2)	/u
8	Contract Services	23		(Exh. D1/Sum Sch 2)	
9	DSM Programs [4]	12		(Exh. D1/Sum Sch 2)	
10	Outbound Affiliates	(8)		(Exh. D1/Sum Sch 2)	
11	Bad Debt	(5)		(Exh. D1/Sum Sch 2)	
12	Capitalization	(14)		(Exh. D1/Sum Sch 2)	/u
13	Non-Utility Allocations	(7)		(Exh. D1/Sum Sch 2)	/u
14	Other	7		(Exh. D1/Sum Sch 2)	/u
15	Sub Total: Net O&M [5]	67		(Exh. D1/Sum Sch 2)	/u
16	Rate Base Growth Net of Tax Changes & Debt Costs	20		(Exh. F1/T1/p.3)	/u
17	ROE Formula Change[2]	19			
18	Capital Structure Change	17		(Exh. E1/T1/p.4)	
19	Revenue Deficiency	71		(Exh. F1/T1/p.2)	/u

Line. No.	Revenue Deficiency/Sufficiency Adjustment	2013	2007	
20	Total deficiency [3]	70.6	17	/u
21	Long-term storage subsidy	0.0	(19)	
22	Shareholder portion of transactional S&T margin	0.8	2	/u
23	Adjusted deficiency	71.4	0	/u

Note:
(1) Adjusted for the storage premium embedded in 2007 rates.
(2) Calculated using 36% of the 2013 rate base and grossed up using the 2013 proposed income tax rate.
(3) Includes ratepayer and shareholder portions of short-term storage, and transportation and exchange revenues and associated costs.
(4) Approximately $8.0 million has been included in rates over the incentive regulation term via the Y factor.
(5) Includes the impacts of O&M associated productivity initiatives in categories where they were achieved.

UNION GAS LIMITED
Pro Forma Consolidated Statements of Income
For the year ending December 31

Line No.	Particulars ($000's)	2012	2013	
		(a)	(b)	
1	Gas sales	1,437,998	1,401,869	
2	Cost of gas sold	721,684	698,398	/u
3	Gas sales margin	716,314	703,471	/u
4	Transportation Revenue	180,668	162,055	/u
5	Storage Revenue	117,718	97,546	/u
6	Other revenue	27,912	27,882	
7	Earnings sharing	-	-	
8		1,042,612	990,954	/u
	Expenses:			
9	Operating and maintenance	396,979	406,854	/u
10	Depreciation and amortization	213,025	206,176	
11	Property and capital taxes	64,294	65,424	
12		674,298	678,454	/u
13	Operating income	368,314	312,500	/u
14	Other income (expense)	(1,000)	(1,000)	
	Interest expense:			
15	Long-term debt	151,500	155,113	/c
16	Redeemable preferred shares	255	255	
17	Amortization of financing expenses	942	1,051	/c
18	Short-term debt	4,784	3,540	/u
19	Interest during construction	(1,329)	(3,068)	
20		156,152	156,891	/u
21	Income before income taxes	211,162	154,609	/u
22	Income taxes	41,988	23,542	/u
23	Net income	169,174	131,067	/u
24	Preferred dividend requirements	2,466	2,670	
25	Earnings applicable to common shares	166,708	128,397	/u

UNION GAS LIMITED
Pro Forma Consolidated Balance Sheets
For the year ending December 31

Assets

Line No.	Particulars ($000's)	2012 (a)	2013 (b)	
	Current assets:			
1	Accounts receivable	516,358	515,483	/u
2	Prepaid expenses	9,093	9,094	
3	Income taxes receivable	10,041	40,645	/u
4	Deferred income taxes - short-term	-	-	
	Inventories:			
5	Gas in underground storage	206,613	214,734	
6	Inventory of spare equipment	30,475	30,615	
7		772,580	810,571	/u
8	Property, plant and equipment	6,760,959	7,085,393	
9	Less: accumulated depreciation	2,242,455	2,370,033	
10		4,518,504	4,715,360	
	Deferred charges:			
11	Balancing Gas	72,963	72,963	
12	Other	447,892	463,684	
13	Goodwill	8,833	8,833	
14		529,688	545,480	
15	Total Assets	5,820,772	6,071,411	/u

UNION GAS LIMITED
Pro Forma Consolidated Balance Sheets
For the year ending December 31

Liabilities and Shareholders' Equity

Line No.	Particulars ($000's)	2012	2013	
		(a)	(b)	
	Current liabilities:			
1	Short-term borrowings	196,943	331,502	/u
2	Accounts payable and accrued charges	579,624	572,109	/u
3	Income and other taxes payable	17,070	17,070	/u
4	Deferred taxes payable - short-term	14,285	15,601	
5	Long-term debt due within 12 months	-	150,000	
6		807,922	1,086,282	/u
7	Long-term debt	2,402,170	2,253,223	/c
8	Redeemable preferred shares	4,859	4,859	
9	Asset retirement obligation	127,530	127,530	
10	Regulatory and other liabilities	488,671	488,671	
11	Deferred income taxes	364,690	357,520	
12	Total liabilities	4,195,842	4,318,085	/u
	Shareholders' equity:			
13	Preference shares	104,500	104,500	
14	Common shares	627,063	627,063	
15	Contributed surplus	159	159	
16	Retained earnings	893,208	1,021,605	/u
17	Total common equity	1,520,430	1,648,827	/u
18	Total shareholders' equity	1,624,930	1,753,327	/u
19	Total liabilities and shareholders' equity	5,820,772	6,071,411	/u

UNION GAS LIMITED
Pro Forma Consolidated Statements of Retained Earnings
For the year ending December 31

Line No.	Particulars ($000's)	2012	2013	
		(a)	(b)	
1	Balance, beginning of year	893,208	1,027,536	/u
	Add:			
2	Net income	169,174	131,067	/u
3		1,062,382	1,158,603	/u
	Deduct:			
	Dividends declared:			
4	Preference shares	2,466	2,670	
5	Common shares	32,380	-	/c
		34,846	2,670	/u
6	Balance, end of year	1,027,536	1,155,933	/u

UNION GAS LIMITED
Pro Forma Consolidated Statements of Cash Flows
For the year ending December 31

Line No.	Particulars ($000's)	2012	2013	
		(a)	(b)	
	Operating Activities			
1	Net income	169,174	131,067	/u
	Add (deduct) non-cash charges to net income:			
2	Depreciation and amortization	214,981	208,459	
3	Deferred income taxes	178	(5,854)	
4	Other	426	1,053	/u
5		384,759	334,725	/u
	Other operating sources:			
6	Accounts receivable	39,796	875	/u
8	Inventories and prepayments	9,918	(8,263)	
9	Accounts payable and other	(65,515)	(54,908)	/u
10		368,959	272,430	/u
	Investment Activities			
11	Additions to property, plant and equipment	(295,558)	(405,319)	
12	Deferred charges and other items	1,000	1,000	
13		(294,558)	(404,319)	
	Financing Activities			
14	Retirement of long-term debt	-	-	
15	Issue of long-term debt	125,000	-	/c
16	Dividends declared	(34,846)	(2,670)	/c
17		90,154	(2,670)	/c
18	Increase/(decrease) in short-term borrowings	(164,555)	134,559	/u
19	Short-term borrowings, beginning of year	361,498	196,943	/u
20	Short-term borrowings, end of year	196,943	331,502	/u

Stephen W. Baker
President

March 21, 2012

Dear Shareholder:

I am pleased to forward you a copy of the Union Gas Limited (Union Gas) 2011 annual report. It contains Union Gas' management's discussion and analysis, management responsibility for financial reporting, consolidated financial results, and corporate directory. I invite you to visit www.sedar.com for electronic versions of Union Gas' consolidated financial statements, management's discussion and analysis, and other filings throughout the year.

Stephen W. Baker
President

This discussion and analysis of Union Gas Limited for the twelve months ended December 31, 2011, should be read in conjunction with the audited consolidated financial statements and accompanying notes. The terms (“we,” “our”, “us” and “Union Gas”) as used in this report refer collectively to Union Gas Limited and its subsidiary unless the context suggests otherwise. These terms are used for convenience only and are not intended as a precise description of any separate legal entity within Union Gas. 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 us, including our most recent Annual Information Form, can be found at www.sedar.com.

FORWARD LOOKING INFORMATION

This Management's Discussion and Analysis (MD&A) includes forward-looking statements. Forward-looking statements are based on management's beliefs and assumptions. These forward-looking statements are identified by terms and phrases such as: anticipate, believe, intend, estimate, expect, continue, should, could, may, plan, project, predict, will, potential, forecast, and similar expressions. Forward-looking statements involve risks and uncertainties that may cause actual results to be materially different from the results predicted. Factors that could cause actual results to differ materially from those indicated in any forward-looking statement include, but are not limited to:

- local, provincial and federal legislative and regulatory initiatives that affect cost and investment recovery, have an effect on rate structure, and affect the speed at and degree to which competition enters the natural gas industries;
- outcomes of litigation and regulatory investigations, proceedings or inquiries;
- weather and other natural phenomena, including the economic, operational and other effects of storms;
- the timing and extent of changes in commodity prices and interest rates;
- general economic conditions which can affect the long-term demand for natural gas and related services;
- potential effects arising from terrorist attacks and any consequential or other hostilities;
- changes in environmental, safety and other laws and regulations;
- the development of alternative energy resources;
- results of financing efforts, including the ability to obtain financing on favourable terms, which can be affected by various factors, including credit ratings and general economic conditions;
- increases in the cost of goods and services required to complete capital projects;
- declines in the market prices of equity and debt securities and resulting funding requirements for defined benefit pension plans;
- growth in opportunities, including the timing and success of efforts to develop pipeline, storage, and other infrastructure projects and the effects of competition;
- the performance of transmission, storage and distribution facilities;
- the extent of success in connecting natural gas supplies to transmission systems and in connecting to expanding gas markets;
- the effects of accounting pronouncements issued periodically by accounting standard-setting bodies;
- conditions of the capital markets during the periods covered by the forward-looking statements; and

- the ability to successfully complete merger, acquisition or divestiture plans; regulatory or other limitations imposed as a result of a merger, acquisition or divestiture; and the success of the business following a merger, acquisition or divestiture.

In light of these risks, uncertainties and assumptions, the events described in the forward-looking statements might not occur or might occur to a different extent or at a different time than we have described. We undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, except as required by law.

GENERAL

Union Gas, one of Canada's Top 100 Employers for 2011, is a major Canadian natural gas storage, transmission and distribution company based in Ontario with 100 years of experience and service to customers. The distribution business serves approximately 1.4 million residential, commercial and industrial customers in more than 400 communities across northern, southwestern and eastern Ontario. Union Gas' growing storage and transmission business offers premium storage and transportation services to customers at the Dawn Hub (Dawn). Dawn is the largest underground storage facility in Canada and one of the largest in North America. It offers customers an important link in the movement of natural gas from Western Canadian and United States (U.S.) supply basins to markets in central Canada and the northeast U.S.

Our distribution system consists of approximately 62,700 kilometres of main and service pipelines. Distribution pipelines carry or control the supply of natural gas from the point of local supply to customers. Our underground natural gas storage facilities have a working capacity of approximately 155 billion cubic feet (Bcf) in 23 underground facilities located in depleted gas fields. The transmission system consists of approximately 4,700 kilometres of high-pressure pipeline and six mainline compressor stations.

Union Gas' common shares are held by Great Lakes Basin Energy L.P., a wholly-owned limited partnership of Westcoast Energy Inc. (Westcoast). Westcoast is an indirect wholly-owned subsidiary of Spectra Energy Corp (Spectra Energy).

Spectra Energy is a Delaware corporation that is a public company in the U.S. and whose shares are listed on the New York Stock Exchange.

Our board of directors is comprised of at least one-third independent directors with the remainder consisting of officers of Union Gas, Westcoast or Spectra Energy and there is no audit committee of the board. The function of an audit committee is carried out at the level of Spectra Energy during the review of its consolidated financial statements.

HIGHLIGHTS

($millions except where noted)	For the Years Ended December 31 **2011**	 2010	 2009
Income			
Total operating revenues	**1,813**	1,830	2,019
Earnings applicable to common shares	**199**	204	173
Dividends			
Dividends on preference shares	**2**	2	2
Dividends on common shares	**145**	190	165
Assets and long-term liabilities			
Total assets	**5,845**	5,585	5,446
Total long-term liabilities	**3,291**	2,935	2,870
Volumes of gas (10^6m^3)[1]			
Distribution volumes	**14,133**	13,314	12,849
Transportation volumes	**23,619**	25,577	22,668
Total throughput	**37,752**	38,891	35,517
Customers *(thousands)*	**1,360**	1,344	1,325
Heating degree days[2] *(degree Celsius)*			
Actual	**3,957**	3,796	4,130
Normal[3]	**4,075**	4,056	4,034

[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 average temperature falls 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.

RESULTS OF OPERATIONS

	For The Three Months Ended December 31			For The Years Ended December 31		
($millions)	2011	2010	**Increase (Decrease)**	2011	2010	**Increase (Decrease)**
Gas sales and distribution revenue	404	441	**(37)**	1,468	1,493	**(25)**
Cost of gas	209	238	**(29)**	755	794	**(39)**
Gas distribution margin	195	203	**(8)**	713	699	**14**
Storage and transportation revenue	78	78	**-**	311	308	**3**
Other revenue	13	6	**7**	34	29	**5**
	286	287	**(1)**	1,058	1,036	**22**
Expenses	165	160	**5**	645	631	**14**
Interest expense	40	41	**(1)**	152	158	**(6)**
Income taxes	17	8	**9**	60	41	**19**
Net income and comprehensive income	64	78	**(14)**	201	206	**(5)**
Preference share dividends	-	-	**-**	2	2	**-**
Net income applicable to common shares	64	78	**(14)**	199	204	**(5)**

Three month period ended December 31, 2011 compared to three month period ended December 31, 2010

Gas sales and distribution revenue. The $37 million decrease was mainly driven by:

- a $17 million decrease in customer usage of natural gas primarily due to weather that was 17% warmer than in the same period in 2010,
- a $12 million decrease from lower natural gas prices[4] passed through to customers without a mark-up, and
- a $9 million decrease due to higher earnings to be shared with customers.

Cost of gas. The $29 million decrease was mainly driven by:

- a $12 million decrease from lower natural gas prices passed through to customers,
- an $11 million decrease in fuel and operating costs, and
- a $7 million decrease due to lower volumes of natural gas sold primarily due to weather that was 17% warmer than in the same period in 2010.

Other revenue. The $7 million increase was primarily due to incentives from customer energy conservation programs.

Expenses. The $5 million increase was primarily due to higher employee benefit costs.

Income taxes. The $9 million increase was due to a higher effective tax rate partially offset by lower pre-tax income.

[4] Natural Gas prices passed through to customers without a mark-up are adjusted quarterly based on the 12 month New York Mercantile Exchange

Twelve month period ended December 31, 2011 compared to twelve month period ended December 31, 2010

Gas sales and distribution revenue. The $25 million decrease was mainly driven by:

- a $141 million decrease from lower natural gas prices passed through to customers without a mark-up, and
- a $12 million decrease due to higher earnings to be shared with customers, partially offset by
- a $118 million increase in customer usage of natural gas primarily due to weather that was more than 4% colder than in the same period in 2010, and
- a $15 million increase from growth in the number of customers.

Cost of gas. The $39 million decrease was mainly driven by:

- a $141 million decrease from lower natural gas prices passed through to customers, and
- a $5 million decrease in fuel and operating costs, partially offset by
- a $106 million increase due to higher volumes of natural gas sold primarily due to weather that was more than 4% colder than in the same period in 2010, and
- a $10 million increase from growth in the number of customers.

Storage and transportation revenue. The $3 million increase was mainly driven by:

- a $10 million increase in short-term transportation due to higher exchange service revenue, partially offset by
- a $7 million decrease primarily due to lower storage prices.

Other revenue. The $5 million increase was primarily due to incentives from customer energy conservation programs.

Expenses. The $14 million increase was primarily the result of higher employee benefit costs.

Income taxes. The $19 million increase was due to a higher effective tax rate and higher pre-tax income.

QUARTERLY RESULTS

($millions)	Q1 2010	Q2 2010	Q3 2010	Q4 2010	Q1 2011	Q2 2011	Q3 2011	Q4 2011
Gas sales and distribution revenue	608	258	186	441	599	276	189	404
Storage and transportation revenue	81	74	75	78	83	78	72	78
Other revenue	6	8	9	6	5	7	9	13
Total operating revenues	695	340	270	525	687	361	270	495
Net income and comprehensive income	85	28	15	78	97	35	5	64
Net income applicable to common shares	84	28	14	78	96	35	4	64

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 weather variations relative to demand during the winter heating season. Changes in natural gas rates that are charged to customers result in corresponding changes in gas sales and distribution revenue. These increases or decreases in gas sales revenue are completely offset in the cost of gas, as a result of the associated regulatory recovery and refund mechanisms.

RATE REGULATION

Union Gas is regulated by the Ontario Energy Board (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. We are subject to regulation with respect to the rates that we may charge our customers, system expansion or facility abandonment, adequacy of service, public safety aspects of pipeline system construction and certain accounting practices.

Since 2006, Union Gas has provided storage services to customers outside its franchise area and new storage services under a framework established by the OEB that supports unregulated storage investments and allows Union Gas to compete against third-party storage providers on the basis of price, terms of service and flexibility and reliability of service. Under that framework, Union Gas was required to share its long-term storage margins with ratepayers until 2011, following which no sharing of margins is required. Existing storage services to customers within Union Gas' franchise area continue to be provided at cost-based rates.

Incentive Regulation

Our distribution rates, beginning January 1, 2008 are set under a multi-year incentive regulation framework. The incentive regulation framework establishes new rates at the beginning of each year through the use of a pricing formula rather than through the examination of revenue and cost forecasts. The incentive regulation framework allows for annual inflationary rate increases, offset by a productivity factor of 1.82% that is fixed for each year. The framework also allows for rate increases in the small volume customer classes where average use is declining, a five-year term, certain adjustments to base rates, the continued pass-through of gas commodity, upstream transportation and demand side management costs, an allowance for unexpected cost changes that are outside of management's control, and earnings sharing between Union Gas and our customers beyond specified earnings levels and equal sharing of tax changes between Union Gas and customers.

In late 2011, the OEB approved Union Gas' 2012 regulated distribution, storage and transmission rates as determined pursuant to the incentive regulation framework. Changes to Union Gas' revenues are not expected to be material as a result of the new rates.

Since 2012 is the final year of our current multi-year incentive regulation framework, we filed an application with the OEB in November 2011 to set our distribution rates under traditional cost-of-service regulation effective January 1, 2013. We plan to file our application for a new multi-year incentive regulation framework after receiving the OEB's decision on our 2013 rates application. The OEB's decision on our 2013 rates application is expected in late 2012.

Non-Commodity Deferral Account Disposition

In April 2011, we applied for the annual disposition of the 2010 non-commodity deferral account balances and the impact of incentive regulation earnings sharing for 2010. The OEB approved a refund payable to customers of approximately $10 million in January 2012 with implementation of the refund proposed to commence April 1, 2012 for a six-month period.

Commodity Rates

Union Gas 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 twelve months and are also subject to review and approval by the OEB on an annual basis. This allows us to adjust customer rates closer to the time of incurrence.

Cost of Capital

In December 2009, the OEB issued its policy report on the Cost of Capital for Ontario's Regulated Utilities. In that report, the OEB determined that Union Gas' utility return on equity should be increased by approximately 125 basis points. The OEB also determined that it would only apply the conclusions from its policy report during cost-of-service applications. As we are currently under a five-year incentive regulation framework, we have incorporated the OEB's policy report determinations in our cost-of-service application for 2013 rates.

Sale of the St. Clair Line

In November 2009, the OEB approved the sale of the St. Clair Line to the Dawn Gateway Pipeline Limited Partnership (DGP), an affiliate company, with such approval expiring on December 31, 2013. The St. Clair Line runs approximately 12 kilometres in the Township of St. Clair located in southwestern Ontario, and was constructed in 1988 to bring new and additional gas supplies to Dawn. The need for the St. Clair Line was largely replaced by the construction of the Vector Pipeline interconnect into the Sarnia Industrial Line in 2005, such that the St. Clair Line was underutilized.

The OEB determined that the sale price of the St. Clair Line for ratemaking purposes should be set at a value higher than net book value and that ratepayers should receive a credit for the cumulative under-recovery in rates of the St. Clair Line from 2003 to the date of sale. Accordingly a credit of $6.4 million was recorded in a deferral account. The OEB also directed Union Gas to record the effect of removing the assets, revenues and costs of the St. Clair Line from regulated operations in a deferral account.

Due to changing market conditions, the construction of the Dawn Gateway pipeline was delayed, and in May 2011, the OEB released its decision finding that the deferral accounts will only be disposed of to ratepayers if the sale of the St. Clair Line is completed, on or before December 31, 2011.

In December 2011, DGP determined that there is insufficient shipper support for the Dawn Gateway Pipeline project at this time. Accordingly the sale of the St. Clair Line has been cancelled and the total deferral account balance of $8.5 million has been taken into income. The St. Clair Line will be returned to regulated rate base upon OEB approval.

Jacob Pool

In June 2010, Union Gas purchased a depleted gas reservoir in the Municipality of Chatham-Kent from Torque Energy Inc. and Liberty Oil & Gas Ltd., known as Jacob Pool. In July 2011, the OEB approved Jacob Pool to be designated as a gas storage area and authorized the injection, storage and removal of gas from this area. Further development of Jacob Pool has been suspended and will be restarted when the market conditions improve.

Demand Side Management

The OEB has been consulting with stakeholders on the guidelines for the next multi-year Demand Side Management (DSM) framework for the natural gas utilities. Final guidelines were issued by the OEB on June 30, 2011. These guidelines allow for annual inflationary increases to the DSM budget, and introduce some changes to the program portfolio. In September 2011, Union Gas filed its DSM plan for 2012-2014 for approval by the OEB. Settlement conferences were held in December 2011 and January 2012. These discussions resulted in a comprehensive three-year settlement on most issues. In February 2012, the OEB accepted the settlement agreement and issued its decision on the unsettled issues. No material impact on Union Gas is expected to result from that decision.

Generally Accepted Accounting Principles of the United States of America (U.S. GAAP)

Union Gas' 2013 rates application uses U.S. GAAP as the basis for the revenue and cost forecasts contained in that application. Since the OEB only approved the use of Canadian GAAP as the appropriate basis for setting rates and for regulatory reporting, the OEB set out a process to hear submissions on the use of U.S. GAAP as a preliminary matter in Union's 2013 rates application. In March 2012, the OEB approved the use of U.S. GAAP for regulatory purposes.

LIQUIDITY AND CAPITAL RESOURCES

We manage cash to maximize value while assuring appropriate amounts of cash are available, as required. We invest our available cash in high-quality money market securities. Such money market securities are designed for the safety of principal and for liquidity, and accordingly do not include equity-based securities.

We meet our short-term cash requirements through funds generated from operations, the utilization of loans from Westcoast, and the issuance of commercial paper. Long-term capital requirements for expansion, maintenance and investments are met through the combination of cash flow from operations, issuance of long-term debt and preference shares.

Changes in Cash Flow

	For The Years Ended December 31	
($millions)	**2011**	2010
Operating activities	**354**	174
Investing activities	**(290)**	(232)
Financing activities	**(74)**	36

Operating Activities

Union Gas' heating season extends from approximately November through March. We begin the heating season with near-capacity natural gas inventory levels which are drawn throughout the heating season. Inventory levels decrease from December and thus contribute to a positive cash flow from operations during the first quarter. 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.

Some of our customers purchase gas directly from marketers. Marketers typically deliver gas to us evenly throughout the year, whereas most of their customers use gas based on seasonality. As part of our normal billing process, we bill the marketers' customers as gas is used and remit this cash to the marketer when gas is delivered to us. Therefore, during the first and fourth quarters of the year, customers typically use more gas than is delivered to us and we collect cash from the marketers' customers creating a positive cash flow. During the second and third quarters, marketers deliver more gas than their customers use, thus creating a significant cash outflow. These are normal seasonal trends.

The primary factors impacting cash flow from operations for 2011 compared to 2010 include higher refunds to customers in 2010 of gas costs collected in 2009 and a large final tax payment in the first quarter of 2010 for 2009 taxes, partially offset by higher gas purchases in 2011.

Investing Activities

The table below is a summary of capital expenditures:

	For The Years Ended December 31 2012	2011	2010
	(estimated)		
Storage and transmission projects	33%	34%	25%
Distribution	53%	51%	59%
General equipment	14%	15%	16%
	100%	100%	100%
Total capital expenditure ($millions)	$301	$290	$232

The table below is a summary of capital project type:

	For The Years Ended December 31 2012	2011	2010
	(estimated)		
Maintenance projects[5]	84%	98%	97%
Expansion projects	16%	2%	3%
	100%	100%	100%

Capital expenditures for 2011 were higher compared to 2010 primarily due to spend on two multi-year maintenance projects that were started in 2010 and substantially completed in 2011. Expansion expenditures in 2012 are expected to be higher than 2011 partially offset by lower 2012 maintenance expenditures, due to the substantial completion of the two multi-year projects. The 2012 expansion expenditures reflect our continued assessment of the timing of projected long-term market requirements and general economic conditions. Based on our current assessment, we believe that expansion opportunities will continue to exist in the future.

As outlined in the financing activities discussion that follows, we have sufficient financing available to meet our investing requirements. Management expects that financing of 2012 projects will be done through a combination of cash generated from operations and available debt facilities.

Financing Activities

We have the following financing arrangements in place:

- A shelf prospectus was filed in September 2010 that permits the issuance of medium-term notes, in one or more series, up to an aggregate principal amount of $500 million and for terms as covered in the pricing supplement at the time of issue with maturities of not less than one year from the date of issue. The shelf will expire in October 2012. As of December 31, 2011, $200 million was available.
    - In May 2011, we retired, at par, $250 million of Series 3 medium-term note debentures at 6.65% per annum.
    - In June 2011, we issued $300 million of Series 9 medium-term note debentures at 4.88% per annum, due June 2041. Net proceeds from the offering have been used for general corporate purposes, including refinancing of the May 2011 retirement.
- In December 2011, the previous $500 million committed credit facility was replaced by a $400 million committed credit facility. This committed credit facility is available to help meet our short-term financing needs. As of December 31, 2011, $121 million was available.

[5] Maintenance projects include costs incurred for new customer attachments. Maintenance projects also include expansion capital for in-franchise customers.

- Our $400 million committed credit facility has a five year term which expires in December 2016 and includes a provision which requires us to repay all borrowings under the facility for a period of two days during the second quarter of each year. This facility is intended to be used primarily to manage the significant changes in working capital experienced by Union Gas as a result of volumes and prices associated with natural gas purchases and sales. Most of the short-term cash requirements are funded through issuing commercial paper at rates generally below the lender's prime rate. Our 2011 commercial paper peaked in December at approximately $279 million.

In order to maintain the common equity component of the capital structure at a level no greater than that approved by the OEB, we typically pay a quarterly dividend to our parent company. During 2011, we paid a quarterly dividend to our parent of $16 million (2010 –$16 million). In December 2011, we paid an additional $80 million dividend to our parent (December 2010 – $125 million).

OUTSTANDING SHARES

	December 31 2011	December 31 2010
Redeemable Preference Shares		
Class A, Series A, 5.5%	**47,672**	47,672
Class A, Series C, 5.0%	**49,500**	49,500
Preference Shares		
Class A, Series B, 6.0%	**90,000**	90,000
Class B, Series 10, 4.88%	**4,000,000**	4,000,000
Common Shares	**57,822,650**	57,822,650

FINANCIAL CONDITION

Ratings Summary

	Standard & Poor's	**DBRS**
Commercial paper	A – 1 (low)[6]	R – 1 (low)
Debentures	BBB+	A
Preference shares	P – 2 (low)[7]	Pfd – 2

Our credit ratings remain unchanged from those reported in the 2010 Annual Report.

The above credit ratings are dependent upon, among other factors, the ability to generate sufficient cash to fund capital and investment expenditures, our results of operations, market conditions and other factors. Our credit ratings could impact our ability to raise capital in the future, impact the cost of our capital and, as a result, have an impact on our liquidity.

[6] Represents Canadian National Scale Commercial Paper Rating.
[7] Represents Canadian Preferred Stock Rating.

CONTRACTUAL OBLIGATIONS

The table below is a summary of our contractual payment obligations, due by period.

($millions)	Total	2012	2013-2014	2015-2016	Thereafter
Long-term debt[8]	4,397	150	441	599	3,207
Redeemable preference shares	5	–	–	–	5
Operating leases	32	6	13	13	–
Purchase obligations[9]	953	526	215	134	78
Environmental obligations[10]	16	4	4	4	4
Contributions to employee future benefit plan[11]	64	64	–	–	–
Total contractual obligations[12]	5,467	750	673	750	3,294

RELATED PARTY TRANSACTIONS

We purchase gas, storage and transportation services at prevailing market prices and under normal trade terms from related parties. During the year ended December 31, 2011, these purchases totalled $56 million (2010 – $11 million). Union Gas also provides storage and transportation services to related parties which totalled $1 million during 2011 (2010 – $1 million).

We provided administrative, management and other services to related parties totalling $12 million (2010 – $10 million), which were billed and recovered at cost. Charges from related parties for administrative and other goods and services were $9 million (2010 – $9 million).

At December 31, 2011 we have receivable balances of $4 million (2010 – $2 million) and payable balances of $7 million (2010 – $3 million) with related parties, all of which are recorded in accounts receivable and accounts payable, respectively.

During 2011, we obtained from and provided unsecured loans to Westcoast. The balance outstanding on these loans at December 31, 2011 was a $99 million payable (2010 – $198 million payable). Interest received on these loans during 2011 totalled less than $1 million (2010 – less than $1 million) and interest paid on these loans totalled less than $1 million (2010 – less than $1 million). Interest on these loans is calculated based on the monthly average of 30-day banker's acceptance rates.

[8] Includes: estimated scheduled interest payments over the life of the associated debt.
[9] Includes: firm capacity payments that provide us with uninterrupted firm access to natural gas transportation and storage; contractual obligations to purchase physical quantities of natural gas; contracts for software and consulting or advisory services; contractual obligations for engineering, procurement and construction costs for pipeline projects.
[10] Includes capital, operating and maintenance expenditures related to the comprehensive certificate of approval.
[11] We are unable to reasonably estimate employee future benefit plan contributions beyond 2012 due primarily to uncertainties about market performance of plan assets.
[12] Excludes cash obligations for asset retirement activities. The amount of cash flows to be paid to settle the asset retirement obligations is not known with certainty as Union Gas may use internal resources or external resources to perform retirement activities. Amounts also exclude reserves for litigation, environmental remediation, annual insurance premiums that are necessary to operate the business and regulatory liabilities because Union Gas is uncertain as to the amount and/or timing of when cash payments will be required. Also, amounts exclude future income taxes and investment tax credits on the Consolidated Balance Sheets since cash payments for income taxes are determined based primarily on taxable income for each discrete fiscal year.

GAS SUPPLY

The gas supply portfolio of Union Gas primarily includes contracts with pricing mechanisms that reflect monthly and daily variations in the price of gas. These contracts are indexed to either the New York Mercantile Exchange natural gas futures contracts, the Canadian Gas Price Reporter that publishes Alberta index prices or the Platt's Inside FERC Dawn Monthly Index.

We continue to monitor and evaluate the new and changing natural gas supply dynamics to determine what opportunities exist for our customers. We have taken steps to allow for the emerging Marcellus Shale gas supplies to serve our Ontario system customers beginning in 2012, including contracting for firm transportation capacity on other pipelines to facilitate moving this supply to Dawn and ultimately to our customers.

OUTLOOK

Gas Sales and Distribution

Demand for natural gas in all markets is expected to remain flat through 2012. Any growth driven by continued low natural gas prices is expected to be offset by reductions in distribution throughput. Distribution throughput is forecasted to continue declining as a result of energy conservation including our DSM initiatives, declining normalized use per customer and a general trend toward warmer weather.

Union Gas continues to focus on promoting conservation and energy efficiency through our DSM programs. In 2010 and 2011, we spent $22 million and $26 million respectively, promoting these programs. We plan to spend approximately $31 million in 2012.

Storage and Transportation

The storage and transportation marketplace continues to deal with the global economic slowdown but is expected to be stable going forward. Weak commodity prices as a result of a more robust North American gas supply balance and narrower seasonal price spreads in the marketplace are resulting in lower unregulated storage values. North American natural gas supplies continue to increase as a result of new supply attachment including liquefied natural gas and development in the U.S. Rocky Mountains, as well as various new shale gas resource projects such as the Barnett, Fayetteville, Woodford and the Marcellus and Utica Shale areas. The development of these new resources has increased overall North American gas supply reserves and is leading to significant new pipeline and storage infrastructure to connect these new supplies to the North American pipeline grid and the associated natural gas consuming market areas. These new supply sources will be available to serve Ontario and Eastern Canadian markets.

Furthermore, we are experiencing a change in traditional natural gas flow patterns as these new shale gas supplies continue to develop. This will continue to provide Union Gas opportunities and challenges for new storage and pipeline infrastructure projects. Union Gas applied to the OEB, during 2010 and again in 2011, for transportation service enhancements to respond to these changing flow patterns. These services were approved by the OEB and will enhance access to emerging supply basins and provide enhanced flexibility to attract gas to Dawn, where it can be stored and delivered to downstream eastern markets.

The location of our storage and transportation facilities, with interconnections between major U.S. markets in the Great Lakes region and the U.S. Northeast continues to support long-term growth opportunities for us. It is our expectation that demand for natural gas in North America will continue to have low growth over the long-term with continued growth in peak day demands.

In September 2011, TransCanada PipeLines Limited (TCPL) filed a proposal with the National Energy Board (NEB) to modify their tolling framework. With the potential for additional long-haul and/or short-haul toll changes, customers may continue to pursue alternative or less expensive sources of delivered supply. Since our system directly connects to the TCPL system, this could result in a decline in the use of our storage and transportation system. Also, declining supply into Dawn from the TCPL system and constraints in takeaway capacity downstream of Union's Parkway compressor station site on the TCPL system may affect liquidity at

Dawn and storage pricing. To address these concerns, we will continue to focus on adding new services to attract new supply to Dawn. We are also evaluating new infrastructure projects that can more directly connect downstream markets and upstream supply to Dawn.

Environmental, Health and Safety

During 2008, we obtained approval from the Ontario Ministry of the Environment (MOE) for a multi-site comprehensive certificate of approval (CC of A) for the permitting of our air and noise emission sources. The CC of A will treat Union Gas as a single integrated natural gas storage, transmission and distribution system incorporating all storage pools, metering and regulating stations, compressor stations and buildings into a single environmental permit. The terms and conditions of the CC of A include significant financial obligations for capital, operating and maintenance expenditures over a period of approximately 10 years, and the total estimated obligation has been included in the Contractual Obligations section of this document. Under the terms of the CC of A, we will be allowed to add and modify facilities without prior approval from the MOE, thereby reducing the risk of delays associated with obtaining environmental permits. Union Gas remains on target to meet the current 10 year plan.

The MOE requires third party audits to confirm that our facilities are operating in accordance with the conditions specified in the CC of A. There have been no major findings to date from these audits.

In May 2011, the Workplace Safety and Insurance Board conducted a Workwell audit at our Company. This audit occurred as a result of an employee vehicle fatality in late 2009. At the conclusion of the audit, we were notified that we had successfully passed the audit and that we were one of a very few multi-site companies in Ontario to have ever passed an audit on the first attempt. This result is a recognition that we not only meet compliance standards, but also have a very strong safety culture.

Global Climate Change

Policymakers at provincial, federal and international levels continue to evaluate potential legislative and regulatory compliance mechanisms to achieve reductions in global greenhouse gas (GHG) emissions in an effort to address the challenge of climate change. It is likely that our assets and operations are or will become subject to direct and indirect effects of current and possible future global climate change regulatory actions in the jurisdictions in which those assets and operations are located. See Risk Factors – Global Climate Change Risk for further discussion.

RISK FACTORS

Our earnings are affected by the risks inherent in the natural gas industry and energy marketplace. In general, our business and 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, the absolute and relative price of alternative energy sources, foreign exchange rates and global competition. In 2012, we expect that the North American economy will experience slow growth.

Sales to Union Gas' 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, and the continued shift to higher efficiency. New customer additions in 2012 are expected to remain flat relative to 2011, however, the ongoing trend towards energy efficiency will continue to put pressure on usage.

A large quantity of our transportation capacity is subject to renewal on an annual basis. Our standard contract terms provide automatic renewal of contracts, after the initial term, for one year at a time unless the customer provides two years prior notice of termination. Due to changing gas supply patterns we have received notice of termination for some capacity in 2012 and 2013 and have continued risk of further contract termination beyond 2013.

For storage contracts, our standard contract terms do not allow for renewals but will typically have contract terms of one to five years.

Commodity Price Risk

Fluctuations in natural gas prices affect our gas purchase costs for our own operating requirements as well as for the gas supply costs we incur for and collect from our system customers. Our gas procurement policy primarily includes contracts with pricing mechanisms that reflect monthly and daily variations in the price of gas. 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 we could incur if a counterparty fails to perform under its contractual obligations. We analyze the customer's financial condition prior to entering into an agreement, obtain collateral when appropriate, establish credit limits and monitor the appropriateness of those limits on an ongoing basis.

Our credit exposure consists of both the risk of collecting receivables for services provided as well as the risk related to gas imbalances that occur as a regular part of the services provided in both the direct purchase market and ex-franchise market.

In the normal course of operations, we provide gas loans to other parties from our holdings of gas in storage. The replacement cost of the gas on loan at December 31, 2011 was $64 million (2010 – $72 million). We manage our credit exposure related to gas loans by subjecting these parties to the same credit policies used for all customers.

Weather Risk

As a primary component of Union Gas rates is volume based, the revenue levels approved by the OEB are impacted by weather. 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 2008 forward. Since a large portion of the gas distributed to the residential and commercial markets 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 on our financial results.

Regulatory Risk

Our natural gas assets and operations are subject to regulation by federal, provincial and local authorities including the OEB and by various federal and provincial authorities under environmental laws. Regulation affects almost every aspect of our business, including the ability to determine terms and rates for services, acquisitions, construction, expansion and operation of facilities, issuance of equity or debt securities, and dividend payments.

In addition, regulators in Canada have taken actions to strengthen market forces in the gas pipeline industry, which have led to increased competition. In a number of key markets, natural gas pipeline and storage operators are facing competitive pressure from a number of new industry participants, such as alternative suppliers as well as traditional pipeline competitors. Increased competition driven by regulatory changes could have a material effect on our business, earnings, financial condition and cash flows.

Most of our pipelines are regulated by the Ontario Technical Standards and Safety Authority (TSSA) while a few are regulated by the NEB. Through our participation on the TSSA Natural Gas Advisory Council and associated Risk Reduction Groups we have the opportunity to provide input and to influence the direction of regulatory changes. Union Gas currently has a robust integrity management program, however amendments to the Ontario regulations being proposed by the TSSA will have an impact on our Integrity Management Program and the direction the U.S. industry is taking may prompt some further regulatory requirements. Specifically the changes being proposed include adopting the 2011 version of CSA Z662, adopting a newly developed security management standard, including the requirements for a utility cross bore program which was already included in a separate Director's Order, and introducing the requirements to identify high consequence areas and consider additional measures to mitigate potential pipeline risk in those areas. We continue to work with the TSSA in their development of the amendments to the Ontario regulations. We have very limited NEB regulated assets, so the amendments proposed related to NEB Management Systems and Performance Measures are not expected to have a significant impact on our business.

Competition Risk

As our distribution business is regulated by the OEB, it is generally not subject to third-party competition within our distribution franchise area. However, as a result of a 2006 decision by the OEB, physical bypass of newly-required facilities even within our distribution franchise area may be permitted. In addition, other companies could enter our markets or regulations could change.

Union Gas competes with other forms of energy available to its customers and end-users, including electricity, coal, propane and fuel oils. Factors that influence the demand for natural gas include price changes, the availability of natural gas and other forms of energy, the level of business activity, conservation, legislation, governmental regulations, the ability to convert to alternative fuels, weather and other factors.

Storage Market Risk

We use market based prices for some of our storage operations and sell our storage services based on natural gas market spreads and volatility. If natural gas market spreads or volatility deviate from historical norms or there is significant growth in the amount of storage capacity available to natural gas markets relative to demand, our approach to managing our market-based storage capacity portfolio may not protect us from significant variations in storage revenues, including possible declines as contracts renew.

Permit Fees Risk

Effective January 1, 2007, the Government of Ontario granted municipalities the right to charge a fee to recover the costs of issuing a permit to access pipelines located within a municipal roadway. During 2011, permit fees levied by municipalities against Union Gas did not have a significant impact on our consolidated financial statements. Should more municipalities start implementing a permit fee or if the amounts increase and these assessments become significant in the future, Union Gas will apply to the OEB to recover the annual cost of these fees in rates.

Financing Risk

Our business is financed to a large degree through debt. The maturity and repayment profile of debt used to finance investments often does not correlate to cash flows from assets. Accordingly, we rely on access to both short-term and long-term capital markets as a source of liquidity for capital requirements not satisfied by the cash flow from operations and to fund investments originally financed through debt. Our long-term debt is currently rated investment-grade by various rating agencies. If the rating agencies were to rate us below investment-grade, our borrowing costs would increase, perhaps significantly. In addition, we would likely be required to pay a higher interest rate in future financings, and our potential pool of investors and funding sources could decrease.

We are subject to long-term debt covenants that include a limitation on the payment of dividends, and requirements for specific interest coverage ratios prior to the issuance of additional long-term debt. Although we do not anticipate any impact to our current financing plans, reduced earnings may limit the payment of future dividends and the level of new long-term debt available to us. We maintain a revolving credit facility to backstop our commercial paper programs for short-term borrowings. This facility includes a financial covenant which limits the amount of debt that can be outstanding as a percentage of total capital. Failure to maintain this covenant could preclude us from issuing commercial paper or borrowing under the revolving credit facility and could require immediate pay down of any outstanding drawn amounts under other revolving credit agreements, which could adversely affect our cash flow.

If we are not able to access capital at competitive rates, our ability to finance operations and implement our strategy may be adversely affected. Restrictions on our ability to access financial markets may also affect our ability to execute our business plan as scheduled. An inability to access capital may limit our ability to pursue improvements or acquisitions that we may otherwise rely on for future growth. Any downgrade or other event negatively affecting the credit ratings could make our costs of borrowing higher or access to funding sources more limited.

Human Resources Risk

Union Gas' workforce consists of both unionized and non-unionized employees. Labour disruptions associated with the collective bargaining process can affect our ongoing operations. Projected changes in workforce demographics and a future shortage of skilled trades represent an issue that is being addressed by Union Gas.

Performance Risk

We have 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 and partners may increase the severity of a default.

Litigation Risk

Union Gas, in the course of its operations, is subject to environmental and other claims, lawsuits and contingencies. Although it is possible that liabilities may be incurred in instances for which no accruals have been made, we have no reason to believe that the ultimate outcome of such matters currently known to us could have a material effect on our consolidated financial statements.

Facility Risk

We carry 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

In 2011, the Ontario Liberal Government was re-elected, albeit with a minority number of seats in the legislature. The province is operating with a large financial deficit and significant spending commitments. As such, it is expected that they will continue to search for new sources of revenues including non-tax revenue streams such as fees and levies.

Environmental, Health and Safety Risk

There are a variety of hazards and operating risks inherent in natural gas storage, transmission, and distribution activities, such as leaks, explosions and mechanical problems that could cause substantial financial losses. In addition, these risks could result in significant injury, loss of human life, significant damage to property, environmental pollution and impairment of operations, any of which could result in substantial losses. For pipeline and storage assets located near populated areas, including residential areas, commercial business centers, industrial sites and other public gathering areas, the level of damage resulting from these risks could be greater. We do not maintain insurance coverage against all of these risks and losses, and any insurance coverage we might maintain may not fully cover the damages caused by those risks and losses. Therefore, should any of these risks materialize, it could have a material adverse effect on our business, earnings, financial condition and cash flows.

Global Climate Change Risk

The current international climate framework, the United Nations-sponsored Kyoto Protocol, prescribes specific targets to reduce GHG emissions for developed countries for the 2008-2012 periods. United Nations-sponsored international negotiations were held in Copenhagen, Denmark in December 2009, in Cancun, Mexico in December 2010 and in Durban, South Africa in December 2011 with the intent of defining a future agreement for 2012 and beyond. In December 2011 after the international negotiations in Durban, South Africa, Canada announced that it is withdrawing from the Kyoto Protocol.

In 2008 the government outlined a regulatory framework mandating GHG reductions from large final emitters. Regulatory design details from the Government of Canada remain forthcoming. However, Canada has reaffirmed its strong preference for a harmonized approach with that of the U.S. Regardless of the timing, we expect a number of our assets and operations will be affected by pending federal climate change regulations. However, the materiality of any potential compliance costs is unknown at this time as the final form of the regulation and compliance options has yet to be determined by policymakers.

A number of provinces are establishing or considering provincial or regional programs that would mandate reductions in GHG emissions including Ontario which is a member of the Western Climate Initiative which also includes the provinces of British Columbia, Manitoba and Quebec. However, the key details of future GHG restrictions and compliance mechanisms remain largely undefined.

In 2011, Ontario regulations for GHG emissions reporting came into effect. The regulation applies to all facilities emitting greater than 25,000 tonnes of carbon dioxide per year from a list of specified activities. Currently, Union Gas is required to report and verify emissions based on general stationary combustion (compressor engines, generators, heaters and boilers).

Due to the uncertainty of Canadian federal and provincial policies, we cannot estimate the potential effect of proposed GHG policies on our future consolidated results of operations, financial position or cash flows. However such legislation could increase our operating costs materially, require material capital expenditures or create additional permitting, which could delay proposed construction projects.

Protecting Against Potential Terrorist Activities

The potential for terrorism because of the high profile of the natural gas industry has subjected our operations to increased risks that could have a material adverse effect on our business. This risk is particularly great for companies, like ours, operating in any energy infrastructure industry that handles volatile gaseous and liquid hydrocarbons. The potential for terrorism has subjected our operations to increased risks that could have a material adverse effect on our business. In particular, we may experience increased capital and operating costs to implement increased security for our facilities and pipelines, such as additional physical facility and pipeline security and additional security personnel. Moreover, any physical damage to high profile facilities resulting from acts of terrorism may not be covered, or covered fully, by insurance. We may be required to expend material amounts of capital to repair any facilities, the expenditure of which could adversely affect our cash flows and business.

Changes in the insurance markets attributable to terrorist attacks may make certain types of insurance more difficult for us to obtain. Moreover, the insurance that may be available to us may be significantly more expensive than our existing insurance coverage. Instability in the financial markets as a result of terrorism or war could also affect our ability to raise capital.

Pension Risk

Our costs of providing defined benefit pension plans are dependent upon a number of factors, such as the rates of return on plan assets, discount rates used to measure pension liabilities, actuarial gains and losses, future government regulation and our contributions made to the plans. Without sustained growth in the pension plan investments over time to increase the value of our plan assets, and depending upon the other factors impacting our costs as listed above, we could experience net asset, expense and funding volatility. This volatility could have a material effect on our earnings and cash flows.

Land Rights

Certain aboriginal groups in Ontario have claimed aboriginal and treaty rights in areas where Union Gas' Dawn storage and transmission assets are located and also in areas where the Dawn-Trafalgar pipeline route is located. The existence of these claims could give rise to future uncertainty regarding land tenure depending upon their negotiated outcome.

CERTIFICATION OF DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

Disclosure Controls and Procedures

We have established and maintained disclosure controls and procedures designed to: (a) provide reasonable assurance that material information required to be disclosed by us is accumulated and communicated to management to allow timely decisions regarding required disclosure; and (b) ensure that material information required to be disclosed by us is recorded, processed, summarized, and reported within the time periods specified in applicable securities legislation.

Our management, with the participation of the President and the Chief Financial Officer, has evaluated the effectiveness of our disclosure controls and procedures as of December 31, 2011, and, based upon this evaluation, the President and the Chief Financial Officer have concluded that these disclosure controls and procedures, as defined by National Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings (NI 52-109), are effective for the purposes set out above.

Internal Control over Financial Reporting

Our management is responsible for designing, establishing and maintaining an adequate system of internal control over financial reporting. Our internal control system was designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes, in accordance with Canadian GAAP. Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with policies and procedures may deteriorate.

Our management, with the participation of our President and the Chief Financial Officer, has conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2011 based on the framework in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on that evaluation, management concluded that our internal control over financial reporting, as defined by NI 52-109, is effective to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements in accordance with Canadian GAAP.

Changes in Internal Control over Financial Reporting

Under the supervision and with the participation of management, including the President and Chief Financial Officer, we have evaluated changes in internal control over financial reporting that occurred during the fiscal quarter and year ended December 31, 2011 and found no change that has materially affected, or is reasonably likely to materially affect, internal control over financial reporting.

Our Board of Directors reviewed and approved the 2011 audited consolidated financial statements and this management's discussion and analysis prior to its release.

CRITICAL ACCOUNTING POLICIES & ESTIMATES

The application of accounting policies and estimates is an important process that continues to evolve as Union Gas' operations change and accounting guidance is issued. Union Gas has identified a number of critical accounting policies and estimates that require the use of significant estimates and judgments.

Management bases its estimates and judgments on historical experience and on other various assumptions that they believe are reasonable at the time of application. The estimates and judgments may change as time passes and more information becomes available. If estimates and judgments are different than the actual amounts recorded, adjustments are made in subsequent periods to take into consideration the new information. Union Gas discusses its critical accounting policies and estimates and other significant accounting policies with senior members of management and the Board of Directors.

Regulatory Accounting

Union Gas continues to follow Canadian GAAP until January 1, 2012, when Union Gas switches to U.S. GAAP. Canadian GAAP allows accounting treatments that may differ for rate-regulated operations from those otherwise expected in non rate-regulated businesses. As a result, we record assets and liabilities that result from the regulated ratemaking process that may not be recorded under Canadian GAAP for non rate-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 ratepayers. 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 rate-regulated entities. Management believes the existing regulatory assets are probable of recovery. This determination reflects the current political and regulatory climate and is subject to change in the future. If future recovery of costs ceases to be probable, asset write-offs could be required to be recognized in current period earnings.

Unbilled Revenue

Revenues from the transportation, storage, distribution and sales of natural gas are recognized when either the service is provided or the product is delivered. Revenues related to these services provided or products delivered but not yet billed are estimated each month. Gas sales and distribution revenue and cost of gas are 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 and historical consumption per heating degree-day. Unbilled revenue recorded at December 31, 2011 was \$116 million (2010 – \$118 million). Differences between actual and estimated unbilled revenues are not material to net income. Included in unbilled revenue are natural gas costs passed through to customers without a mark-up. At December 31, 2011 \$74 million (2010 – \$73 million) was included in unbilled revenue for the cost of natural gas.

Employee Future Benefits

Critical estimates and assumptions are required to account for employee future benefits and changes to these estimates and assumptions could result in a material difference to our employee future benefit plan obligation.

The following is a summary of the sensitivity of key assumptions used to record the employee future benefit liability:

Sensitivity of key assumptions

($millions)	**Registered Pension Plan and Supplemental Pension Arrangements**		**Other Post-Retirement Benefits**	
Assumed change in:	**1% Increase**	**1% Decrease**	**1% Increase**	**1% Decrease**
Discount rate				
Change in 2011 net benefit cost	**(7)**	7	**(1)**	1
Change in benefit obligations	**(83)**	93	**(10)**	11
Health care cost trend rate				
Change in 2011 net benefit cost	**N/A**	N/A	**1**	(1)
Change in benefit obligations	**N/A**	N/A	**8**	(7)
Expected rate of return on assets				
Change in 2011 net benefit cost	**(5)**	5	**N/A**	N/A

ACCOUNTING CHANGES

New Accounting Pronouncements – 2011

The Canadian Institute of Chartered Accountants (CICA) issued Section 1601, Consolidated Financial Statements and Section 1602, Non-controlling Interests in January 2009, to be implemented in January 2011. Sections 1601 and 1602 require all entities to report non-controlling interests in subsidiaries as equity on the Consolidated Balance Sheet. In addition, Section 1602 requires entities to report net income and comprehensive income for both the controlling and non-controlling interests. We adopted Section 1601 prospectively and Section 1602 retrospectively as required. The Consolidated Financial Statements and related information in this report, reflect the application of the reporting requirements of Sections 1601 and 1602.

Conversion to U.S. GAAP

In February 2008, the Accounting Standards Board (AcSB) of the CICA confirmed that publicly accountable enterprises would be required to adopt International Financial Reporting Standards (IFRS) in place of GAAP for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011.

In September 2010, the AcSB decided to offer an optional one year deferral for adopting IFRS for qualifying entities with rate regulated activities and permit such entities to continue to apply Part V – Pre-changeover accounting standards of the CICA Handbook during that period. Union Gas is a qualifying entity for purposes of this deferral.

While our IFRS conversion project was on track to meet the original conversion deadline, we have elected to use the deferral offered by the AcSB. This decision was made to allow us to convert at the same time as many companies in our industry, and to review our options, including the adoption of U.S. GAAP instead of IFRS.

In the third quarter of 2011, the securities regulators approved our election to report under U.S. GAAP instead of IFRS for financial years commencing on January 1, 2012, but before January 1, 2015.

Conversion plan

Throughout 2011 we have captured comparative figures and converted to U.S. GAAP on January 1, 2012. Employee training was provided throughout the year and will continue beyond the conversion process. As our parent prescribes to U.S. GAAP, the conversion to U.S. GAAP did not have a significant impact on our financial systems and business activities.

Key accounting differences

The main area of difference in reporting under U.S. GAAP is employee future benefits accounting. We recorded a charge to accumulated other comprehensive income and recognized a regulatory asset in the opening consolidated balance sheet upon conversion to U.S. GAAP primarily as a result of actuarial losses to be recognized under U.S. GAAP.

The consolidated financial statements and all information in this report have been prepared by and are the responsibility of management. The consolidated 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 Union Gas' 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 fulfils its responsibility for financial reporting and for final approval of the consolidated financial statements.

The Board of Directors meets regularly with management, the internal auditors and the shareholders' auditors to review the consolidated financial statements, the Independent Auditor's 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 Board of Directors, as does the Director of Internal Audit Services.

Deloitte & Touche LLP performed an independent audit of the 2011 and 2010 consolidated financial statements in this report. Their independent professional opinion on the fairness of these consolidated financial statements is included in the Independent Auditor's Report.

March 21, 2012

Stephen W. Baker	J. Patrick Reddy
President	Chief Financial Officer

Deloitte.

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Independent Auditor's Report

To the Shareholders of
Union Gas Limited

We have audited the accompanying consolidated financial statements of Union Gas Limited, which comprise the consolidated balance sheets as at December 31, 2011 and December 31, 2010, and the consolidated statements of income and comprehensive income, retained earnings, and cash flows for the years then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Part V Pre-Changeover Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

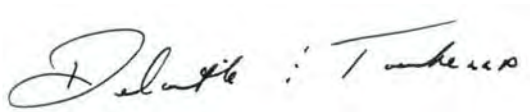
Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Union Gas Limited as at December 31, 2011 and December 31, 2010 and the results of its operations and its cash flows for the years then ended in accordance with Part V Pre-Changeover Canadian generally accepted accounting principles.



Chartered Accountants
Licensed Public Accountants
March 21, 2012

UNION GAS LIMITED
Consolidated Statements of Income and Comprehensive Income

For the Years Ended December 31 ($millions)	**2011**	2010
Gas sales and distribution revenue	**1,468**	1,493
Cost of gas (note 15)	**755**	794
Gas distribution margin	**713**	699
Storage and transportation revenue (note 15)	**311**	308
Other revenue	**34**	29
	1,058	1,036
Expenses		
Operating and maintenance (note 15)	**379**	364
Depreciation and amortization	**205**	200
Property and capital taxes	**61**	67
	645	631
Income before interest and income taxes	**413**	405
Interest expense (notes 6 and 15)	**152**	158
Income before income taxes	**261**	247
Income taxes (note 14)	**60**	41
Net income and comprehensive income	**201**	206
Preference share dividends	**2**	2
Net income and comprehensive income applicable to common shares	**199**	204

(See accompanying notes)

UNION GAS LIMITED
Consolidated Statements of Retained Earnings

For the Years Ended December 31 ($millions)	**2011**	2010
Retained earnings, beginning of year	**710**	696
Net income and comprehensive income	**201**	206
Dividends		
Preference shares	**(2)**	(2)
Common shares	**(145)**	(190)
Retained earnings, end of year	**764**	710

(*See accompanying notes)*

UNION GAS LIMITED
Consolidated Balance Sheets

As at December 31 ($millions)	**2011**	2010
Assets		
Current assets		
Cash and cash equivalents	**2**	12
Accounts receivable (notes 3 and 15)	**533**	516
Inventories (note 4)	**263**	174
Future income taxes (note 14)	**7**	14
Total current assets	**805**	716
Property, plant and equipment (note 5)		
Cost	**6,615**	6,370
Accumulated depreciation	**2,120**	1,994
Net property, plant and equipment	**4,495**	4,376
Regulatory and other assets (note 13)	**545**	493
Total Assets	**5,845**	5,585
Liabilities and Equity		
Current liabilities		
Short-term borrowings (note 15)	**99**	198
Commercial paper (note 6)	**279**	157
Accounts payable and accrued charges (notes 3 and 15)	**618**	586
Income taxes payable (note 14)	**53**	8
Long-term debt (note 6)	–	250
Total current liabilities	**1,049**	1,199
Long-term liabilities		
Long-term debt (note 6)	**2,277**	1,978
Mandatorily redeemable preference shares (note 7)	**5**	5
Future income taxes (note 14)	**383**	361
Asset retirement obligations (note 9)	**134**	123
Regulatory and other liabilities (note 13)	**492**	468
Total long-term liabilities	**3,291**	2,935
Total Liabilities	**4,340**	4,134
Equity		
Share capital (note 8)	**732**	732
Retained earnings	**764**	710
Non-controlling interest	**9**	9
Total Equity	**1,505**	1,451
Total Liabilities and Equity	**5,845**	5,585

(See accompanying notes)

Approved by the Board

Director

Director

UNION GAS LIMITED
Consolidated Statements of Cash Flows

For the Years Ended December 31 ($millions)	**2011**	2010
Operating Activities		
Net income	**201**	206
Items not affecting cash		
Depreciation and amortization	**205**	200
Future income taxes	**8**	25
Changes in working capital		
Accounts receivable	**(15)**	(42)
Inventories	**(85)**	32
Account payables, accrued charges and other	**40**	(247)
	354	174
Investing Activities		
Capital expenditures	**(290)**	(232)
Financing Activities		
Net increase (decrease) in short-term borrowings	**(99)**	198
Net increase in commercial paper	**122**	118
Long-term debt issued	**300**	250
Long-term debt repayments	**(250)**	(222)
Dividends paid	**(147)**	(308)
	(74)	36
Change in cash and cash equivalents, during the year	**(10)**	(22)
Cash and cash equivalents, beginning of year	**12**	34
Cash and cash equivalents, end of year	**2**	12
Supplementary Disclosure of Cash Flow Information:		
Cash payments of interest	**154**	152
Cash payments of income taxes	**8**	96

(See accompanying notes)

UNION GAS LIMITED
Notes to Consolidated Financial Statements
December 31, 2011 and 2010

Union Gas Limited (Union Gas or 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 market participants. 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 approximately 4,700 kilometres of high-pressure transmission pipeline and approximately 62,700 kilometres of distribution main and service pipelines. The Company's underground natural gas storage facilities have a working capacity of more than 155 billion cubic feet (Bcf).

1. Significant Accounting Policies

Accounting Principles

The consolidated financial statements of the Company have been prepared in accordance with Part V – Pre-changeover Canadian generally accepted accounting principles (GAAP) and certain transactions have been recorded using accounting principles for rate-regulated enterprises as discussed below under ―Regulation." The preparation of financial statements in accordance with 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, income tax expense, employee future benefit expense, estimated useful life of property, plant and equipment and asset retirement obligations.

Accounting Changes

Consolidated Financial Statements and Non-controlling Interest

The Canadian Institute of Chartered Accountants (CICA) issued Section 1601, Consolidated Financial Statements and Section 1602, Non-controlling Interests in January 2009 under Part V of the CICA handbook, to be implemented in January 2011. Sections 1601 and 1602 require all entities to report non-controlling interests in subsidiaries as equity on the Consolidated Balance Sheet. In addition, Section 1602 requires entities to report net income and comprehensive income for both the controlling and non-controlling interests. The Company adopted Section 1601 prospectively and Section 1602 retrospectively as required. The Consolidated Financial Statements and related information in this report, reflect the application of the reporting requirements of Sections 1601 and 1602.

Conversion to Generally Accepted Accounting Principles of the United States of America (U.S. GAAP)

In February 2008, the Accounting Standards Board (AcSB) of the CICA confirmed that publicly accountable enterprises would be required to adopt International Financial Reporting Standards (IFRS) in place of GAAP for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011.

In September 2010, the AcSB decided to offer an optional one year deferral for adopting IFRS for qualifying entities with rate regulated activities and permit such entities to continue to apply Part V – Pre-changeover accounting standards of the CICA Handbook during that period. Union Gas is a qualifying entity for purposes of this deferral.

We elected to use the deferral offered by the AcSB. This decision was made to allow us to convert at the same time as many companies in our industry, and to review our options, including the adoption of U.S. GAAP instead of IFRS.

In the third quarter of 2011, the securities regulators approved our election to report under U.S. GAAP instead of IFRS for financial years commencing on January 1, 2012, but before January 1, 2015. Effective January 1, 2012, we converted to U.S. GAAP.

Principles of Consolidation

The consolidated financial statements of the Company include the accounts of Union Gas and its subsidiary, Huron Tipperary Limited Partnership I, of which the Company owns 75%.

Regulation

The Company is regulated by the Ontario Energy Board (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, with the exception of the items noted below, system expansion or facility abandonment, adequacy of service, public safety aspects of pipeline system construction and certain accounting principles. The OEB has determined that it will forbear from regulating the prices for long-term storage services. The Storage Forbearance Decision created an unregulated storage operation within Union Gas and provides the framework required to support new storage investments.

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 its ability to achieve forecast revenues and manage costs.

Rates effective January 1, 2007 were approved by the OEB on the basis of the traditional cost of service framework. Effective January 1, 2008, the Company began a five year incentive regulation term. The incentive regulation framework establishes new rates at the beginning of each year through the use of a pricing formula rather than through the examination of revenue and cost forecasts. The Company has applied to set rates for 2013 on a cost of service basis.

The Company follows Canadian GAAP, which may differ for regulated operations from those otherwise expected in non rate-regulated businesses. As a result, the Company records assets and liabilities that result from the regulated ratemaking process that may not be recorded under GAAP for non rate-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, or for certain net revenues beyond a pre-established threshold. 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 could be recognized in current period earnings.

Revenue Recognition

Revenues from the transportation, storage, distribution and sales of natural gas are recognized when either the service is provided or the product is delivered. Revenues related to these services provided or products delivered but not yet billed are estimated each month.

Gas Sales and Cost of Gas

Gas sales revenue is recorded on the basis of regular meter readings and estimates of customer volume 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 amounts approved by the OEB in the determination of customer sales rates. Differences between the OEB approved reference amounts and those costs actually incurred are deferred in either accounts receivable or accounts payable and accrued charges 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 used 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.

As part of the Company’s OEB-approved incentive regulation framework, an earnings sharing mechanism exists whereby earnings above an allowable return on equity are shared with ratepayers. A provision of $17 million was recognized as a reduction of gas sales and distribution revenue and as an obligation in accounts payable and accrued charges for 2011 (2010 – $4 million).

Cash and Cash Equivalents

Cash and cash equivalents consist of cash and short-term investments, with an original maturity of three months or less.

Income Taxes

The asset and liability method of tax allocation is used in the accounting for income taxes. Under this method, future income tax assets and liabilities are recognized for differences between the financial reporting and tax basis of assets and liabilities at enacted, or the substantively enacted, tax rates in effect for the years in which the differences are expected to reverse.

Inventories

Gas in storage for resale to customers is carried at costs approved by the OEB in the determination of customer sales rates. The difference between the approved cost and the actual cost of the gas purchased is deferred in either accounts receivable or accounts payable and accrued charges for future disposition subject to approval by the OEB. Inventories of materials and supplies are valued at the lower of 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.

Regulated depreciation is provided on the straight-line method at various rates based on the average service life of each class of property. Unregulated depreciation rates are based on useful life.

Regulated depreciation rates are determined by periodic review. The depreciation rates for regulated property, plant and equipment are approved by the OEB. Unregulated depreciation rates are determined by management.

When Union Gas retires regulated property, plant and equipment, the Company charges the original cost plus the cost of retirement, less salvage value, to accumulated depreciation and amortization. When the Company sells entire regulated operating units, or retires non-regulated properties, the cost is removed from the property account and the related accumulated depreciation and amortization accounts are reduced. Any gain or loss is recorded in earnings, unless otherwise required 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.

Stock-Based Compensation

Our employees participate in a stock-based compensation plan sponsored by Spectra Energy Corp (Spectra Energy). For employee awards, equity classified stock-based compensation cost is measured at the grant date based on the fair value of the award. Liability classified stock-based compensation cost is measured at the grant date based on the current stock price and re-measured at each reporting period until settlement. The compensation cost is recognized as expense over the requisite service period, which generally begins on the date the award is granted through the earlier of the date the award vests or the date the employee becomes retirement eligible. Awards, including stock options, granted to employees that are already retirement eligible are deemed to have vested immediately upon issuance, and therefore, compensation cost for those awards is recognized on the date such awards are granted.

In addition, certain of our employees that previously participated in our 1989 Long Term Incentive Share Plan have the ability to receive a portion of their converted stock option awards as a stock appreciation right (SAR) paid in cash. Union Gas accounts for these by measuring the amount by which the quoted market price of the underlying stock exceeds the SAR base stock price at the balance sheet date.

Employee Benefit Plans

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

The Company accrues 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 with the market related adjustment determined over a three-year period.

Past service costs from plan amendments are amortized on a straight-line basis over the expected average remaining service lifetime 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 expected average remaining service lifetime of active employees.

The average remaining service period of active employees covered by the pension plans and the other post-retirement benefit plans is 10 and 18 years, respectively.

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

2. Financial Statement Effects of Rate Regulation

The Company records assets and liabilities that result from the regulated ratemaking process that would not be recorded under GAAP for non-regulated entities. See note 1 for further discussion.

($millions)	Financial Statement Location	Recovery/ Settlement Period	**December 31 2011**	December 31 2010
Assets				
Other deferrals – current	a	A	**28**	12
Storage deferrals	a	A	**5**	–
Gas in storage inventory	b	A	**54**	28
Other deferrals – long-term	c	B	**1**	3
Future income taxes – long-term	c	B/C	**235**	214
Total assets			**323**	257
Liabilities				
Other deferrals – current	d	A	**30**	31
Gas cost deferrals	d	A	**54**	39
Storage deferrals	d	A	**12**	9
Asset removal costs	e	C	**427**	409
Total liabilities			**523**	488

In the absence of rate regulation, the Company's future income tax asset (current) would have been $16 million lower in 2011 (2010 - $20 million lower), and the future income tax liability (long-term) would have been $48 million higher in 2011 (2010 - $48 million higher) as a result of the elimination of the above regulatory assets and liabilities.

Financial Statement Classification

(a) Accounts receivable
(b) Inventories
(c) Regulatory and other assets
(d) Accounts payable and accrued charges
(e) Regulatory and other liabilities

Recovery/Settlement Period

(A) Remaining recovery / settlement is less than 1 year
(B) Remaining recovery / settlement is from 2 to 10 years
(C) Remaining recovery / settlement is over the remaining life of the associated assets

Other deferrals – current

As prescribed by regulatory order, the Company has various amounts included in customer rates that are intended to recover specifically-identified costs. To the extent that the actual costs differ from forecast costs or revenues, the variance is deferred for future recovery from or refund to ratepayers. In the absence of rate regulation, after-tax earnings for 2011 could have been $12 million lower (2010 – $3 million higher) because GAAP for non-regulated entities would require that all customer rate revenue and costs be recognized in income when earned.

Storage deferrals

The Company earns revenue for providing storage services to customers. The forecast of this revenue is one component used to establish Union Gas' rates for services. Storage deferral accounts accumulate any difference between the actual revenue earned in providing these storage services and the forecast revenue approved by the OEB for ratemaking purposes. In the absence of rate regulation, GAAP for non-regulated entities would require that actual storage revenue be recognized in income when earned. After-tax earnings for 2011 could have been $2 million lower (2010 – $8 million lower), if these transactions were accounted for under GAAP for non-regulated entities.

Gas in storage

Gas in storage is carried at the weighted average cost of gas as approved by the OEB. In the absence of rate regulation, after-tax earnings for 2011 could have been $26 million lower (2010 – $9 million higher), because GAAP for non-regulated entities would require that gas in storage be recorded at the lower of cost and net realizable value.

Future income taxes

The accounting standard related to income taxes requires rate-regulated enterprises to recognize future income tax assets and liabilities, and an associated regulatory asset or liability, if applicable, for the amount of future income taxes expected to be recovered from or refunded to ratepayers, and to present these amounts on a gross basis in the financial statements. In the absence of rate regulation, after-tax earnings for 2011 could have been $16 million lower (2010 – $30 million lower) because GAAP for non-regulated entities would require that these amounts be recognized in earnings in the current period.

Gas cost deferrals

The Company and the OEB have a mechanism in place to change gas commodity rates on a quarterly basis, to ensure that customers' rates reflect future expected costs 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. These deferred amounts are subject to review and approval by the OEB on an annual basis in the normal course. 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, after-tax earnings for the 2011 could have been $11 million higher (2010 – $101 million lower), because GAAP for non-regulated entities would require that actual commodity costs be recognized as an expense when incurred.

Asset removal costs

The Company has recorded a regulatory liability, as a result of estimated removal costs for property that does not have an associated legal retirement obligation. In the absence of rate regulation, these costs may not have been recorded and after-tax earnings for 2011 could have been $13 million higher (2010 – $8 million higher).

Property, plant and equipment

In the absence of rate regulation, property, plant and equipment may not include overhead costs, accretion of asset retirement obligations, asset removal costs and gain/loss on retirement or sale of depreciable assets since these costs may have been charged to earnings in the period in which they occurred. As such, annual operating and maintenance costs, interest expense, gain/loss on disposal of assets and depreciation could have been impacted by the amounts capitalized. These amounts are not readily determinable.

3. 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 done with gas volumes, changes in the balances do not have an impact on the Company's cash flow from operating activities.

At December 31, 2011 accounts receivable and accounts payable include approximately $195 million (2010 – $194 million) related to gas imbalances and gas balancing services.

4. Inventories

($millions)	December 31 2011	December 31 2010
Gas in storage	**247**	157
Materials and supplies	**16**	17
	263	174

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

5. Net Property, Plant and Equipment

($millions)	December 31 2011	December 31 2010
Cost		
Distribution	**3,729**	3,594
Transmission	**1,706**	1,639
Storage	**913**	870
General	**267**	267
	6,615	6,370
Accumulated depreciation		
Distribution	**1,143**	1,086
Transmission	**567**	498
Storage	**305**	277
General	**105**	133
	2,120	1,994
Net book value	**4,495**	4,376

The depreciation range of each class of property is as follows:

Distribution	27-60 years
Transmission	30-50 years
Storage	5-50 years
General	4-38 years

Depreciation rates used during the year ended December 31, 2011 resulted in a composite rate of 3.25% (2010 – 3.26%).

Included in property, plant and equipment are the following:

($millions)	December 31 2011	December 31 2010
Assets not subject to depreciation[13]	**147**	161
Asset retirement cost	**41**	35
Interest charge capitalized during the year	**3**	1

[13] Assets not subject to depreciation include land, base pressure gas in storage reservoirs and assets under construction.

6. Debt and Credit Facility

Long-term Debt

($millions)		**December 31 2011**	December 31 2010
6.65%	Series 3, redeemed May, 2011	**–**	250
7.90%	1994 Series debentures, due February 24, 2014	**150**	150
11.50%	1990 Series debentures, due August 28, 2015	**150**	150
4.64%	Series 5, due June 30, 2016	**200**	200
9.70%	1992 Series II debentures, due November 6, 2017	**125**	125
5.35%	Series 6, due April 27, 2018	**200**	200
8.75%	1993 Series debentures, due August 3, 2018	**125**	125
8.65%	Senior debentures, due October 19, 2018	**75**	75
4.85%	Series 7, due April 25, 2022	**125**	125
8.65%	1995 Series debentures, due November 10, 2025	**125**	125
5.46%	Series 6, due September 11, 2036	**165**	165
6.05%	Series 7, due September 2, 2038	**300**	300
5.20%	Series 8, due July 23, 2040	**250**	250
4.88%	Series 9, due June 21, 2041	**300**	–
		2,290	2,240
Less: deferred financing charges		**13**	12
		2,277	2,228
Less: current portion		**–**	250
		2,277	1,978

The Company's long-term debt is unsecured. The weighted average cost of long-term debt as at December 31, 2011 was 6.6% (2010 – 6.8%). Principal repayment requirements on long-term debt are as follows:

($millions)	Total	2012	2013	2014	2015	2016	Thereafter
Long-term debt	2,290	–	–	150	150	200	1,790

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, 2011 and 2010, the Company is in compliance with all such covenants.

Total interest paid on long-term debt in 2011 was $151 million (2010 – $150 million).

Available Credit Facility and Restrictive Debt Covenants

	Expiration Date	**Credit Facility Capacity**	**Outstanding at December 31, 2011 Commercial Paper**
Multi-year syndicated[14]	2016	400	279

The issuance of commercial paper and other facility borrowings reduces the amount available under the credit facility.

The Company's credit agreement contains various financial and other covenants, including the maintenance of certain financial ratios. Failure to meet those covenants beyond applicable grace periods could result in

[14] Credit facility contains a covenant requiring the debt-to-total capitalization ratio to not exceed 75% and a provision which requires Union Gas to repay all borrowings under the facility for a period of two days during the second quarter of each year.

accelerated due dates and/or termination of the agreement. As of December 31, 2011, the Company was in compliance with those covenants. In addition, the credit agreement allows for the acceleration of payments or termination of the agreement due to non-payment, or in some cases, due to the acceleration of other significant indebtedness of the borrower or some of its subsidiaries.

A majority of the Company's short-term cash requirements are funded through the issuance of commercial paper. The weighted average rate on outstanding commercial paper as of December 31, 2011 was 1.05% (2010 – 1.05%).

Total interest paid on short-term debt in 2011 was $3 million (2010 – $2 million).

7. Mandatorily Redeemable Preference Shares

		Outstanding at			
Authorized		**December 31 2011**	December 31 2010	**December 31 2011**	December 31 2010
(shares)		*(shares)*		*($millions)*	
Class A – 112,072	Series A, 5.5%	**47,672**	47,672	**3**	3
	Series C, 5.0%	**49,500**	49,500	**2**	2
				5	5

The Class A, Series A and C Preference Shares 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.

8. Share Capital

		Outstanding at			
	Authorized	**December 31 2011**	December 31 2010	**December 31 2011**	December 31 2010
	(shares)	*(shares)*		*($millions)*	
Preference shares:					
Class A, Series B, 6%	90,000	**90,000**	90,000	**5**	5
Class B, Series 10, 4.88%	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, Series B Preference Shares are cumulative and redeemable at $55 per share at the option of the Company.

The Class B, Series 10 Preference Shares are cumulative and redeemable at $25 per share at the option of the Company and, at the option of the holders, convertible back into Series 11 shares every five years commencing January 1, 2014. Union Gas may redeem at any time all, but not less than all, of the outstanding Series 10 Shares. The dividend rate of the Series 10 Shares is floating at an annual rate equal to 80% of the prime rate until December 31, 2013.

9. Asset Retirement Obligation

The Company has a legal obligation to disconnect, purge and cap abandoned pipeline, as well as capping abandoned storage wells. 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.

The Company has non-asbestos AROs which include 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, 2011, the estimated undiscounted cash flows required to settle our AROs was $618 million (2010 – $587 million), calculated using an inflation rate of 2.9% per annum (2010 – 2.0%). The estimated fair value of this liability was $134 million (2010 – $123 million). The estimated cash flows of new obligations incurred during the year have been discounted at a rate of 3.08% per annum (2010 – 3.80%). At December 31, 2011, the timing of payment for settlement of the obligations ranges from 1 to 147 years.

Reconciliation of Asset Retirement Obligations:

($millions)	**December 31 2011**	December 31 2010
Balance, beginning of year	**123**	108
Liabilities incurred	**5**	10
Liabilities settled	**–**	(1)
Accretion	**6**	6
Balance, end of year	**134**	123

10. 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 Gas. 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. 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.

The Spectra Energy 2007 Long-Term Incentive Plan (the 2007 LTIP), as amended and restated, provides for the granting of stock options, restricted stock awards and units, unrestricted stock awards and units, and other equity-based awards, to employees and other key individuals who perform services for Spectra Energy. A maximum of 40 million shares of common stock may be awarded under the 2007 LTIP. Union Gas employees participate in the 2007 LTIP.

Options granted under the 2007 LTIP are issued with exercise prices equal to the fair market value of Spectra Energy common stock on the grant date, have ten year terms and generally vest over a three year term. Compensation expense related to stock options is recognized over the requisite service period. The requisite service period for stock options is the same as the vesting period, with the exception of retirement eligible employees, who have shorter requisite service periods ending when the employees become retirement eligible. Spectra Energy issues new shares upon exercising or vesting of share-based awards. The Black-Scholes option-pricing model is used to estimate the fair value of options at grant date.

Restricted, performance and phantom stock awards granted under the 2007 LTIP typically become 100% vested on the three-year anniversary of the grant date. The fair value of the awards granted is measured based on the fair value of the shares on the date of grant. Related compensation expense is recognized over the requisite service period which is the same as the vesting period.

At the time of the Spectra Energy spin-off from Duke Energy, Duke Energy converted stock options, restricted stock awards, performance awards and phantom stock awards (collectively, Stock-Based Awards) of Duke

Energy common stock held by Spectra Energy employees and Duke Energy employees. One replacement Duke Energy Stock-Based Award and one-half Spectra Energy Stock-Based Award were distributed to each holder of Duke Energy Stock-Based Awards for each award held at the time of the spin-off. The Spectra Energy Stock-Based Awards resulting from the conversion are considered to have been issued under the 2007 LTIP.

Spectra Energy allocated pre-tax stock-based compensation expense included in continuing operations to Union Gas for 2011 and 2010 as follows, the components of which are further described below:

($millions)	**December 31 2011**	December 31 2010
Phantom Stock	**1**	1
Performance Awards	**2**	1
Total	**3**	2

Stock Options

	Shares	**Weighted-Average Exercise Price US$**
Outstanding at beginning of year	**201,758**	**$25**
Transfers in/(out)	**–**	**–**
Granted	**–**	**–**
Exercised	**(25,007)**	**25**
Forfeited	**(16,636)**	**31**
Outstanding at end of year	**160,115**	**$24**
Options exercisable at year-end	**160,115**	**$24**

	Options Outstanding			**Options Exercisable**	
Exercise Prices US$	Number Outstanding At 12/31/11	Weighted-Average Remaining Contractual Life(in years)	Weighted-Average Exercise Price US$	Number Exercisable At 12/31/11	Weighted-Average Exercise Price US$
$11 – 15	19,450	1.2	$12	19,450	$12
$16 – 20	–	–	–	–	–
$21 – 25	124,300	5.2	25	124,300	25
$26 – 30	8,415	0.1	29	8,415	29
$31 – 37	7,950	0.2	33	7,950	33
> $37	–	–	–	–	–
Total	160,115	4.2	$24	160,115	$24

The Company did not award non-qualified stock options to employees during 2011 or 2010. As of December 31, 2011 all stock options are fully vested.

Performance Awards

Under the 2007 LTIP, the Company can also grant stock-based and cash-based performance awards. The performance awards generally vest over three years at the earliest, if performance metrics are met. The cash-based awards will be settled in cash at vesting. The Company granted 31,800 stock-based awards and 31,800 cash-based awards with fair values of US $1 million for each of the grants to employees during 2011. The Company granted 59,400 stock-based performance awards with a fair value of US $2 million during 2010. The unvested and outstanding performance awards granted contain market conditions based on the total shareholder return (TSR) of Spectra Energy common stock relative to a pre-defined peer group. The stock-based awards are valued using the Monte Carlo valuation method. The cash-based awards are valued at Spectra Energy's current stock price and are re-measured at each reporting period until settlement.

Weighted-Average Assumptions for Stock-Based Performance Awards

	December 31 2011	December 31 2010
Risk free interest rate	**1.2%**	1.4%
Expected life (years)	**3**	3
Expected volatility Spectra Energy	**37.7%**	37.9%
Expected volatility Peer Group	**21.2-59.6%**	22.3-58.5%
Market Index	**30.3%**	30.3%
Expected dividend yield	**–**	–

The risk-free rate of return was determined based on a yield of three year U.S. Treasury bonds on the grant date. The expected volatility was established based on historical volatility over three years using daily stock price observations. A shorter period was used if three years of data was not available. Because the award payout includes dividend equivalents, no dividend yield assumption is required.

The total fair value of the performance shares vested was US $1 million in 2011 and none in 2010, as Spectra Energy performance awards were first granted in 2008. As of December 31, 2011, the Company expects to recognize US $2 million of future compensation cost related to stock awards over a weighted-average period of less than two years.

Phantom Stock Awards

Stock-based phantom awards granted under the 2007 LTIP generally vest over three years. The Company awarded 47,200 phantom awards with a fair value of US $1 million during 2011, and 65,600 phantom awards with a fair value of US $1 million during 2010.

The total fair value of the phantom shares vested was US $975,602 in 2011 and US $778,935 in 2010. As of December 31, 2011, the Company expects to recognize US $1 million of future compensation cost related to stock awards over a weighted-average period of less than two years.

11. Capital Management

The Company's objectives in managing its capital include the continuation of its ability to serve customers and to generate the OEB allowed rate of return for its shareholders while maintaining the OEB-approved level of common equity.

In managing capital, management considers both debt and equity. The mix of debt and equity components is driven by prevailing market conditions, as the Company may take advantage of lower interest rates by issuing debt or utilizing available credit facilities. The Company is required by Undertakings to the Lieutenant Governor in Council of Ontario to maintain sufficient common equity at the level approved by the OEB. The quarterly dividend payment is determined to allow the Company to maintain the common equity component at the level approved by the OEB.

Various debt covenants require the Company's Indebtedness[15] not to exceed 75% of Total Capitalization[16].

[15] Indebtedness includes short-term borrowings, commercial paper, long-term debt and mandatorily redeemable preference shares.
[16] Capitalization includes equity and indebtedness.

As at December 31, 2011 and 2010, the Company was in compliance with the following externally imposed capital requirements. The Company monitors these requirements on a quarterly basis.

	December 31 2011	December 31 2010
OEB-approved minimum Common Equity	**36.00%**	36.00%
Allowed Return on Equity – regulated operations	**8.54%**	8.54%
Maximum Total Indebtedness to Total Capitalization	**75.00%**	75.00%
Actual Total Indebtedness to Total Capitalization	**63.90%**	64.10%

12. Financial Instruments

Under Canadian GAAP, financial instruments are classified into one of the following five categories: held-for trading, held to maturity investments, loans and receivables, available-for-sale financial assets and other financial liabilities.

The carrying value of the Company's financial instruments are classified into the following categories:

Classification

($millions)	**December 31 2011**	December 31 2010
Financial assets held for trading[17]	**2**	12
Loans and receivables[18]	**296**	301
Other financial liabilities[19]	**2,889**	2,793

The fair values of the Company's financial instruments are not materially different from their carrying value, with the exception of the Company's long-term debt of $2,290 million (2010 – $2,240 million). Based on current interest rates for debt with similar terms and maturities, the fair market value is estimated to be $2,849 million (2010 – $2,610 million).

Fair value hierarchy

Financial instruments recorded at fair value on the Consolidated Balance Sheet are valued using a fair value hierarchy that reflects the significance of the inputs used in making the measurements. The fair value hierarchy has the following levels:

Level 1 - valuation based on quoted prices (unadjusted) in active markets for identical assets or liabilities;

Level 2 - valuation techniques based on inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly (i.e. as prices) or indirectly (i.e. derived from prices);

Level 3 - valuation techniques using inputs for the asset or liability that are not based on observable market data (unobservable inputs).

The fair value hierarchy requires the use of observable market inputs whenever such inputs exist. A financial instrument is classified to the lowest level of the hierarchy for which a significant input has been considered in measuring fair value.

Cash and cash equivalents are the only financial instruments recorded at fair value on the Consolidated Balance Sheet and are classified as level 1.

[17] Includes cash and cash equivalents
[18] Includes trade and other receivables
[19] Includes accounts payable and accrued charges, short-term borrowings, commercial paper, long-term debt, and mandatorily redeemable preference shares

Interest rate risk

Interest rate risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market interest rates. The long-term debt bears interest at fixed rates and therefore the cash flow exposure is not significant. However, the fair value of loans having fixed rates of interest could fluctuate because of changes in market interest rates. The fair value of short-term borrowings has a limited exposure to interest rate risk due to their short-term maturity.

Credit risk

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligation. The maximum exposure to credit risk of the Company at period end is the carrying value of its financial assets. The Company's principal customers for natural gas transportation and storage services are industrial end-users, marketers, local distribution companies and utilities. The Company's distribution customers are primarily industrial and residential end-users. These concentrations of customers may affect the Company's overall credit risk.

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, 2011 is $64 million receivable (2010 - $72 million receivable). 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.

The Company manages its credit risk on cash and cash equivalents by dealing solely with reputable banks and financial institutions. To manage its credit risk on accounts receivable, the Company performs ongoing credit reviews of all its customers. In cases where the credit quality of a customer does not meet the Company's requirements, a cash deposit, letter of credit or parental guarantee is required. Deposits held by the Company at December 31, 2011 amounted to $48 million (2010 - $51 million). Significant financial difficulties of the debtor, the probability that the debtor will enter bankruptcy or financial reorganization, and default or delinquency in payments are considered indicators that the account receivable may be uncollectible and therefore should be included in the allowance for doubtful accounts.

Union Gas continues to utilize its established risk management policies and procedures to ensure the appropriate monitoring of customer credit positions and, based on current evaluations, does not expect any significant negative impacts associated with these positions.

The following table sets forth details of the age of trade receivables that are not impaired as well as the allowance for the doubtful accounts:

($millions)	**December 31 2011**	December 31 2010
Current	**263**	284
30 Days over due	**10**	9
60 Days over due	**4**	3
90+ Days over due	**7**	6
Total trade accounts receivable	**284**	302
Allowance for doubtful accounts	**(4)**	(5)
Total trade accounts receivable, net[20]	**280**	297

For the years ended December 31, 2011 and 2010, no one customer accounted for more than 10% of sales or 10% of receivables.

Equity Price Risk

Our costs of providing non-contributory defined benefit retirement and postretirement benefit plans are dependent upon, among other things, rates of return on plan assets. These plan assets expose us to price fluctuations in equity markets. In addition, our captive insurance company maintains various investments to

[20] The carrying amount of accounts receivable is impacted by changes in gas prices, which may fluctuate significantly from year to year.

fund certain business risks and losses. Those investments may, from time to time, include investments in equity securities. Currently, we do not invest in equity securities other than employee benefits plan assets.

Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its obligations as they become due. The Company manages its liquidity risk by forecasting cash flows from operations and anticipated investing and financing activities. The Company has credit facilities available to help meet short-term financing needs (note 6).

The following are the contractual maturities of the undiscounted cash flows of financial liabilities as at December 31, 2011:

($millions)	Total	2012	2013–2014	2015–2016	Thereafter
Short-term borrowings	99	99	–	–	–
Commercial paper	279	279	–	–	–
Accounts payable and accrued charges	618	618	–	–	–
Long-term debt (including principal and interest)	4,397	150	441	599	3,207
Mandatorily redeemable preference shares	5	–	–	–	5
Total	5,398	1,146	441	599	3,212

13. Employee Future Benefits

The Company sponsors five registered defined benefit pension plans and one registered pension plan with both a defined benefit provision and a defined contribution provision. Our eligible employees 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. Other post-retirement benefits provided include health and dental benefits, life insurance coverage and a health care spending account.

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 associated with the change in accounting for Employee Future Benefits 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 EARSL of employees active at the date of the amendment. The amount by which the net unamortized cumulative actuarial gain or loss based on the market related value of assets 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. The average remaining service period of the active employees eligible for other post-retirement benefits is 18 years.

The Company made the following employee future benefit contributions:

($millions)	**December 31 2011**	December 31 2010
Defined benefit plans	**88**	40
Defined contribution pension plan	**5**	5
Supplemental pension	**1**	1
Other post-retirement benefits	**3**	2
	97	48

Actuarial Valuations

	Pension Benefit Plans	**Other Post-Retirement Benefits**
Most recent	January 1, 2011	January 1, 2009
Next scheduled	January 1, 2012	January 1, 2012

Benefit Obligations, Plan Assets and Funded Status

	Years Ended December 31			
	Pension		Other	
($millions)	**2011**	2010	**2011**	2010
Change in benefit obligations				
Balance, beginning of year	**655**	585	**69**	60
Employer current service cost	**12**	11	**2**	2
Member contributions	**3**	3	**–**	–
Interest cost	**33**	34	**4**	3
Benefits paid	**(31)**	(30)	**(3)**	(2)
Past service cost	**–**	7	**–**	–
Actuarial loss	**42**	45	**5**	6
Balance, end of year	**714**	655	**77**	69
Change in fair value of assets				
Fair value, beginning of year	**503**	443	**–**	–
Actual return on plan assets	**–**	45	**–**	–
Employer contributions	**38**	42	**3**	2
Member contributions	**3**	3	**–**	–
Benefits paid	**(31)**	(30)	**(3)**	(2)
Fair value, end of year	**513**	503	**–**	–
Funded status				
Net funded status	**(201)**	(152)	**(77)**	(69)
Unamortized net actuarial loss	**313**	258	**21**	17
Unamortized past service costs	**10**	12	**–**	–
Unamortized transitional obligation	**5**	6	**7**	8
Contributions remitted after measurement date	**61**	10	**–**	–
Accrued benefit asset (liability), end of year	**188**	134	**(49)**	(44)
Classification of accrued benefit assets (liabilities)				
Regulatory and other assets	**208**	152	**–**	–
Accounts payable and accrued charges	**(1)**	(1)	**(3)**	(3)
Regulatory and other liabilities	**(19)**	(17)	**(46)**	(41)
Accrued benefit asset (liability)	**188**	134	**(49)**	(44)
Allocation of assets to major classes				
Equity securities	**49%**	54%	**–**	–
Debt securities	**50%**	46%	**–**	–
Cash and cash equivalents	**1%**	–	**–**	–

For 2011 and 2010, all of the defined benefit pension plans had accrued benefit obligations that exceeded the fair value of plan assets. The other post-retirement benefit plans are not pre-funded.

Net benefit cost

	Years Ended December 31			
	Pension		Other	
($millions)	**2011**	2010	**2011**	2010
Current service cost	**12**	11	**2**	2
Interest cost	**33**	34	**4**	3
Actual return on plan assets	**–**	(45)	**–**	–
Actuarial losses	**42**	45	**5**	6
Past service cost	–	7	**–**	–
Elements of employee future benefits costs before adjustments to recognize the long-term nature of employee future benefit costs	**87**	52	**11**	11
Adjustments to recognize the long-term nature of employee future benefit costs:				
Difference between actual and expected return	**(34)**	11	**–**	–
Difference between actual and recognized actuarial gains in year	**(21)**	(31)	**(4)**	(6)
Difference between actual and recognized past service costs in year	**2**	(5)	**–**	–
Amortization of transitional obligation	**1**	1	**1**	2
Defined benefit costs recognized	**35**	28	**8**	7
Defined contribution cost	**5**	5	**–**	–
Total net benefit cost	**40**	33	**8**	7

Weighted average assumptions used to determine benefit liability

	Years Ended December 31			
	Pension		Other	
	2011	2010	**2011**	2010
Discount rate at measurement date	**4.60%**	5.04%	**4.64%**	5.11%
Rate of compensation increase	**3.25%**	3.25%	**3.25%**	3.25%
Initial overall health care trend rate	**–**	–	**7.50%**	8.00%
Annual rate of decline in health care trend rate	**–**	–	**0.50%**	0.50%
Ultimate health care cost trend rate	**–**	–	**5.00%**	5.00%
Year that the rate reaches the ultimate trend rate	**–**	–	**2017**	2017

Weighted average assumptions used to determine net benefit cost

	Years Ended December 31			
	Pension		Other	
	2011	2010	**2011**	2010
Discount rate	**5.04%**	5.62%	**5.11%**	5.69%
Expected rate of return on plan assets	**7.00%**	7.00%	**–**	–
Rate of compensation increases	**3.25%**	3.50%	**3.25%**	3.50%
Initial overall health care trend rate	**–**	–	**8.00%**	8.00%
Annual rate of decline in health care trend rate	**–**	–	**0.50%**	0.50%
Ultimate health care cost trend rate	**–**	–	**5.00%**	5.00%
Year that the rate reaches the ultimate trend rate	**–**	–	**2017**	2016

Sensitivity of key assumption

($millions)	**Other Post-Retirement Benefits**	
Assumed change in health care cost trend rate	**1% Increase**	**1% Decrease**
Change in obligation	**8**	**(7)**

14. Income Taxes

The provision for income taxes consists of the following:

($millions)	**December 31 2011**	December 31 2010
Current	**52**	16
Future	**8**	25
	60	41

The year-over-year change in the components of current and future 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 2011 were $8 million (2010 - $96 million).

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

($millions)	**December 31 2011**	December 31 2010
Income before income taxes	**261**	247
Statutory income tax rate (percent)	**28.25**	31.0
Statutory income tax rate applied to accounting income	**74**	77
Increase/(decrease) resulting from:		
Future tax recovery resulting from tax rate changes	**–**	(4)
Future regulatory income tax payable/receivable recorded through tax expense	**(19)**	(32)
Other – net	**5**	–
Provision for income taxes	**60**	41
Effective rate of income tax (percent)	**23.0**	16.6

The future income taxes recorded in current assets of $7 million (2010 – $14 million) arise from temporary differences primarily related to regulatory deferral accounts.

The long-term future income tax liability of $383 million (2010 - $361 million) includes the following:

($millions)	**December 31 2011**	December 31 2010
Temporary differences related to pension asset	**38**	26
Temporary differences related to accelerated depreciation rates	**345**	335
	383	361

15. Related Party Transactions

The Company purchases gas, storage and transportation services at prevailing market prices and under normal trade terms from related parties. During the year ended December 31, 2011, these purchases totalled $56 million (2010 – $11 million). Union Gas also provides storage and transportation services to related parties which totalled $1 million during 2011 (2010 – $1 million).

The Company provided administrative, management and other services to related parties totalling $12 million (2010 – $10 million), which were billed and recovered at cost. Charges from related parties for administrative and other goods and services were $9 million (2010 – $9 million).

At December 31, 2011 the Company had receivable balances of $4 million (2010 – $2 million) and payable balances of $7 million (2010 – $3 million) with related parties, all of which are recorded in accounts receivable and accounts payable, respectively.

During 2011, the Company obtained from and provided unsecured loans to Westcoast. The balance outstanding on these loans at December 31, 2011 was a $99 million payable (2010 – $198 million payable). Interest received on these loans during 2011 totalled less than $1 million (2010 – less than $1 million) and interest paid on these loans totalled less than $1 million (2010 – less than $1 million). Interest on these loans is calculated based on the monthly average of 30-day banker's acceptance rates.

16. Guarantees

The Company has various financial guarantees which are issued in the normal course of business. The Company enters into these arrangements to facilitate a commercial transaction with a third party by enhancing the value of the transaction to the third party. To varying degrees, these agreements involve elements of performance and credit risk, which are not included on the Consolidated Balance Sheet. The possibility of having to perform under these guarantees is largely dependent upon future operations of other third parties or the occurrence of certain future events. The Company's potential exposure under these agreements can range from a specific dollar amount to an unlimited dollar amount depending on the nature of the claim and the particular transaction. The Company is unable to estimate the total potential amount of future payments under these agreements due to several factors, such as unlimited exposure under certain guarantees.

17. 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 could have a significant impact on its consolidated financial statements.

DIRECTORS

David G. Unruh

Stephen W. Baker

Bruce E. Pydee

OFFICERS

Stephen W. Baker
Chair and President

J. Patrick Reddy
Chief Financial Officer

M. Richard Birmingham
Vice President, Regulatory and Public Affairs

Bruce E. Pydee
Vice President and General Counsel

Bohdan I. Bodnar
Vice President, Human Resources

Menelaos Ydreos
Vice President, Government and Aboriginal Affairs

Mark J. Isherwood
Vice President, Business Development – Storage and Transmission

Paul Rietdyk
Vice President, Engineering, Construction and Storage and Transmission Operations

Michael P. Shannon
Vice President, Distribution Operations

Joe R. Martucci
Vice President, Finance

Guy G. Buckley
Vice President and Treasurer

Timothy J. Kennedy
Vice President, Federal Government Affairs

Paul K. Haralson
Assistant Treasurer

Patricia M. Rice
Corporate Secretary

Leigh A. Hodgins
Assistant Secretary

Joseph Marra
Assistant Secretary

CORPORATE INFORMATION

Transfer Agent and Registrar **CIBC Mellon**

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

Class A Preference, Series B – 6% (UNG.PR.D)

REGISTERED OFFICE
50 Keil Drive North Chatham,
Ontario N7M 5M1

ANNUAL REPORT 2010

Filed: 2011-11-10
EB-2011-0210
Exhibit A3
Tab 2

unionGas
A Spectra Energy Company

Julie Dill
President

March 16, 2011

Dear Shareholder:

I am pleased to forward you a copy of the Union Gas Limited (Union Gas) 2010 annual report. It contains Union Gas' management's discussion and analysis, management responsibility for financial reporting, consolidated financial results, and corporate directory. I invite you to visit www.sedar.com for electronic versions of Union Gas' consolidated financial statements, management's discussion and analysis, and other filings throughout the year.

Julie Dill
President

This discussion and analysis of Union Gas Limited for the twelve months ended December 31, 2010, should be read in conjunction with the audited consolidated financial statements and accompanying notes. The terms ("we," "our", "us" and "Union Gas") as used in this report refer collectively to Union Gas Limited and its subsidiary unless the context suggests otherwise. These terms are used for convenience only and are not intended as a precise description of any separate legal entity within Union Gas. 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 us, including our most recent Annual Information Form, can be found at www.sedar.com.

FORWARD LOOKING INFORMATION

This Management's Discussion and Analysis (MD&A) includes forward-looking statements. Forward-looking statements are based on management's beliefs and assumptions. These forward-looking statements are identified by terms and phrases such as: anticipate, believe, intend, estimate, expect, continue, should, could, may, plan, project, predict, will, potential, forecast, and similar expressions. Forward-looking statements involve risks and uncertainties that may cause actual results to be materially different from the results predicted. Factors that could cause actual results to differ materially from those indicated in any forward-looking statement include, but are not limited to:

- local, provincial and federal legislative and regulatory initiatives that affect cost and investment recovery, have an effect on rate structure, and affect the speed at and degree to which competition enters the natural gas industries;
- outcomes of litigation and regulatory investigations, proceedings or inquiries;
- weather and other natural phenomena, including the economic, operational and other effects of storms;
- the timing and extent of changes in commodity prices and interest rates;
- general economic conditions which can affect the long-term demand for natural gas and related services;
- potential effects arising from terrorist attacks and any consequential or other hostilities;
- changes in environmental, safety and other laws and regulations;
- the development of alternative energy resources;
- results of financing efforts, including the ability to obtain financing on favourable terms, which can be affected by various factors, including credit ratings and general economic conditions;
- increases in the cost of goods and services required to complete capital projects;
- declines in the market prices of equity and debt securities and resulting funding requirements for defined benefit pension plans;
- growth in opportunities, including the timing and success of efforts to develop pipeline, storage, and other infrastructure projects and the effects of competition;
- the performance of transmission, storage and distribution facilities;
- the extent of success in connecting natural gas supplies to transmission systems and in connecting to expanding gas markets;
- the effects of accounting pronouncements issued periodically by accounting standard-setting bodies;
- conditions of the capital markets during the periods covered by the forward-looking statements; and

- the ability to successfully complete merger, acquisition or divestiture plans; regulatory or other limitations imposed as a result of a merger, acquisition or divestiture; and the success of the business following a merger, acquisition or divestiture.

In light of these risks, uncertainties and assumptions, the events described in the forward-looking statements might not occur or might occur to a different extent or at a different time than we have described. We undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, except as required by law.

GENERAL

Union Gas is a major Canadian natural gas storage, transmission and distribution company based in Ontario with 100 years of experience and service to customers. The distribution business serves approximately 1.3 million residential, commercial and industrial customers in more than 400 communities across northern, southwestern and eastern Ontario. Union Gas' growing storage and transmission business offers premium storage and transportation services to customers at the Dawn Hub (Dawn). Dawn is the largest underground storage facility in Canada and one of the largest in North America. It offers customers an important link in the movement of natural gas from Western Canadian and U.S. supply basins to markets in central Canada and the northeast U.S.

Our distribution system consists of approximately 60,600 kilometres of main and service pipelines. Our underground natural gas storage facilities have a working capacity of approximately 155 billion cubic feet (Bcf) in 23 underground facilities located in depleted gas fields. The transmission system consists of approximately 5,000 kilometres of high-pressure pipeline and six mainline compressor stations.

Union Gas' common shares are held by Great Lakes Basin Energy L.P., a wholly-owned limited partnership of Westcoast Energy Inc. (Westcoast). Westcoast is a wholly-owned subsidiary of Spectra Energy Corp (Spectra Energy).

Spectra Energy is a Delaware corporation that is a public company in the United States (U.S.) and whose shares are listed on the New York Stock Exchange.

Our board of directors is comprised of at least one-third independent directors with the remainder consisting of officers of Union Gas, Westcoast or Spectra Energy and there is no audit committee of the board. The function of an audit committee is carried out at the level of Spectra Energy during the review of its consolidated financial statements.

HIGHLIGHTS

	For the Years Ended December 31		
($millions except where noted)	**2010**	2009	2008
Income			
Total operating revenues	**1,830**	2,019	2,130
Earnings applicable to common shares	**204**	173	175
Dividends			
Dividends on preference shares	**2**	2	5
Dividends on common shares	**190**	165	115
Assets and long-term liabilities			
Total assets	**5,585**	5,446	4,856
Total long-term liabilities	**2,939**	2,874	2,505
Volumes of gas (10^6m^3)[1]			
Distribution volumes	**13,314**	12,849	13,844
Transportation volumes	**25,577**	22,668	25,181
Total throughput	**38,891**	35,517	39,025
Customers *(thousands)*	**1,344**	1,325	1,309
Heating degree days[2] *(degree Celsius)*			
Actual	**3,796**	4,130	4,161
Normal[3]	**4,056**	4,034	4,070

[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 average temperature falls 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.

RESULTS OF OPERATIONS

($millions)	For The Three Months Ended December 31 2010	2009	Increase (Decrease)	For The Years Ended December 31 2010	2009	Increase (Decrease)
Gas sales and distribution revenue	441	458	**(17)**	1,493	1,684	**(191)**
Cost of gas	238	276	**(38)**	794	1,026	**(232)**
Gas distribution margin	203	182	**21**	699	658	**41**
Storage and transportation revenue	78	71	**7**	308	299	**9**
Other revenue	6	11	**(5)**	29	36	**(7)**
	287	264	**23**	1,036	993	**43**
Expenses	160	163	**(3)**	631	608	**23**
Other (income) and expenses, net	-	2	**(2)**	-	2	**(2)**
Interest expense	41	41	**-**	158	160	**(2)**
Income taxes	8	8	**-**	41	48	**(7)**
Net income	78	50	**28**	206	175	**31**
Preference share dividends	-	-	**-**	2	2	**-**
Net income applicable to common shares	78	50	**28**	204	173	**31**

Three month period ended December 31, 2010 compared to three month period ended December 31, 2009

Gas sales and distribution revenue. The $17 million decrease was mainly driven by:

- a $35 million decrease from lower natural gas prices[4] passed through to customers without a mark-up, and
- a $7 million decrease due to higher earnings to be shared with customers, partially offset by
- a $25 million increase in customer usage of natural gas due to colder weather.

Cost of gas. The $38 million decrease was mainly driven by:

- a $35 million decrease from lower natural gas prices passed through to customers without a mark-up, and
- a $15 million decrease in operating fuel costs, partially offset by
- a $23 million increase due to higher volumes of natural gas sold due to colder weather.

Storage and transportation revenue. The $7 million increase in storage and transportation revenues was attributable to an increase in long term storage and long term transportation services provided to customers. These increases were partially offset by a decrease in short term storage services provided to customers.

Twelve month period ended December 31, 2010 compared to twelve month period ended December 31, 2009

Gas sales and distribution revenue. The $191 million decrease was mainly driven by:

- a $182 million decrease from lower natural gas prices passed through to customers without a mark-up, and
- a $23 million decrease in customer usage of natural gas due to weather that was more than 8% warmer than in 2009, partially offset by

[4] Natural gas prices passed through to customers without a mark-up are based on the 12 month New York Mercantile Exchange forecast.

- an $11 million increase due to a 2009 charge for a settlement on 2008 earnings to be shared with customers, and
- a $6 million increase due to growth in the number of customers.

Cost of gas. The $232 million decrease was mainly driven by:

- a $182 million decrease from lower natural gas prices passed through to customers without a mark-up,
- a $31 million decrease in operating fuel costs, and
- a $7 million decrease due to lower volumes of natural gas sold as a result of weather that was more than 8% warmer than in 2009.

Storage and transportation revenue. The $9 million increase in storage and transportation revenues was attributable to an increase in transportation services provided to customers and an increase in long-term storage resulting from a lower 2010 approved ratio of earnings to be shared with customers.

Expenses. The $23 million increase was the result of higher employee costs primarily related to pension costs that are associated with higher amortization of pension plan asset market value losses that have occurred in recent years.

Income taxes. The $7 million decrease was primarily due to a lower effective tax rate partially offset by higher pre-tax income.

QUARTERLY RESULTS

($millions)	Q1 2009	Q2 2009	Q3 2009	Q4 2009	Q1 2010	Q2 2010	Q3 2010	Q4 2010
Gas sales and distribution revenue	788	254	184	458	608	258	186	441
Storage and transportation revenue	83	72	73	71	81	74	75	78
Other revenue	6	9	10	11	6	8	9	6
Total operating revenues	877	335	267	540	695	340	270	525
Net income	108	6	11	50	85	28	15	78
Net income applicable to common shares	107	6	10	50	84	28	14	78

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 weather variations relative to demand during the winter heating season. Changes in natural gas rates that are charged to customers result in corresponding changes in gas sales and distribution revenue. These increases or decreases in gas sales revenue are completely offset in the cost of gas, as a result of the associated regulatory recovery and refund mechanisms.

RATE REGULATION

Union Gas is regulated by the Ontario Energy Board (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. We are subject to regulation with respect to the rates that we may charge our customers, system expansion or facility abandonment, adequacy of service, public safety aspects of pipeline system construction and certain accounting practices.

In 2006, the OEB determined that it will forbear from regulating the prices for long-term storage services. The Storage Forbearance Decision created an unregulated storage operation within Union Gas and provides the framework required to support new storage investments. The decision requires Union Gas to continue to share long-term storage margins with ratepayers over a four-year phase-out period that started in 2008. Effective in 2011, there will no longer be any sharing of margins with Union Gas customers on long-term storage transactions.

Incentive Regulation

Our distribution rates, effective January 1, 2008 are set under a multi-year incentive regulation framework. The incentive regulation framework establishes new rates at the beginning of each year through the use of a pricing formula rather than through the examination of revenue and cost forecasts. The incentive regulation framework allows for annual inflationary rate increases, offset by a productivity factor of 1.82% that is fixed for each of the next five years. The framework also allows for rate increases in the small volume customer classes where average use is declining, a five-year term, certain adjustments to base rates, the continued pass-through of gas commodity, upstream transportation and demand side management costs, an allowance for unexpected cost changes that are outside of management's control, earnings sharing between Union Gas and our ratepayers beyond specified earnings levels and equal sharing of income tax changes between Union Gas and ratepayers.

The incentive regulation framework included a provision for a review of that framework if we experienced a variance of 3% or more between our actual utility return on equity (ROE) as normalized for weather and the benchmark utility ROE determined by the OEB. Our weather-normalized utility ROE for 2008 exceeded the upper review threshold, and accordingly, we filed for a review by the OEB in April 2009.

In June 2009, we recorded an $11 million charge as a result of a settlement approved by the OEB that amended the incentive regulation framework effective for 2008 by requiring us to share 90% of any utility ROE of 300 basis points or more above the benchmark utility ROE for the year with our customers. The $11 million charge represents the adjustment to credit to customers with 90% of our 2008 utility earnings that exceeded the 2008 benchmark utility ROE by 300 points.

In late 2010, the OEB approved Union Gas' 2011 regulated distribution, storage and transmission rates as determined pursuant to the incentive regulation framework. Changes to Union Gas' revenues are not expected to be material as a result of the new rates.

Non-Commodity Deferral Account Disposition

In April 2010, we applied for the annual disposition of the 2009 non-commodity deferral account balances. The combined impact on customers, including the impact of incentive regulation earnings sharing for 2009, is a credit of approximately $15 million. A settlement was reached with intervenors in July 2010, and approved by the OEB in August for changes to rates as of October 1, 2010.

Commodity Rates

Union Gas 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 twelve months and are also subject to review and approval by the OEB on an annual basis. This allows us to adjust customer rates closer to the time of incurrence.

Cost of Capital

In December 2009, the OEB issued its policy report on the Cost of Capital for Ontario's Regulated Utilities. In that report, the OEB determined that Union Gas' utility return on equity should be increased by approximately 125 basis points. The OEB also determined that it would only apply the conclusions from its policy report during cost-of-service applications. Accordingly, as we are currently under a five-year incentive regulation framework, we will incorporate the OEB's policy report determinations in our cost-of-service application for 2013 rates. That application is expected to be made by the end of 2011.

Sale of the St. Clair Line

In December 2008, we filed an application with the OEB to sell our St. Clair Line to the Dawn Gateway Pipeline Limited Partnership (DGP). The St. Clair Line runs approximately 12 kilometres in the Township of St. Clair located in southwestern Ontario, and was constructed in 1988 to bring new and additional gas supplies to Dawn. The need for the St. Clair Line was largely replaced by the construction of the Vector Pipeline in 2005, such that the St. Clair Line is underutilized.

Spectra Energy and DTE Pipeline Company, through various affiliates, have formed a 50:50 joint venture that proposes to offer a point-to-point transportation service from the Belle River Mills storage facility in Michigan to Dawn. As part of this joint venture, DGP was formed to own and operate the St. Clair Line and a new 17 kilometre section of pipeline to be constructed from the eastern end of the St. Clair Line to Dawn to support this new transportation service. In November 2009, the OEB approved the sale of the St. Clair Line from Union Gas to DGP, with such approval expiring on December 31, 2013. The OEB also determined that the sale price for ratemaking purposes should be set at a value higher than net book value as proposed by Union Gas and that ratepayers should receive a credit for the cumulative under-recovery in rates of the St. Clair Line from 2003 to the date of sale. A decision on the amount of the ratepayer credit was issued by the OEB in March 2010, establishing the amount of the credit as $6.4 million. The OEB also directed Union Gas to record the effect of removing the assets, revenues and costs of the St. Clair Line from regulated operations in a deferral account. In March 2010, the OEB approved DGP's proposal to construct a new 17 kilometre section of pipeline from the eastern end of the St. Clair Line to Dawn and a new light-handed regulatory framework for the Ontario-based portion of the new transportation service offered by DGP.

Since the OEB approved the proposed sale of our St. Clair Line to DGP in March 2010, rapidly changing market conditions have resulted in DGP and its shippers agreeing to delay construction of the Dawn Gateway Pipeline until November 2011 or November 2012, depending on market conditions. As a result of the delay, the sale of the St. Clair Line to DGP was not completed and the deferral accounts associated with the sale of the St. Clair Line have not been disposed of at this time. In February 2011, we filed evidence with the OEB requesting a further delay of the disposition of the deferral accounts. A hearing date to address this evidence has been set for April 6, 2011. DGP shippers have agreed to a final assessment of the viability of the Dawn Gateway Pipeline by November 2011, for possible service in 2012. If the shippers do not support the project at that time, the Dawn Gateway Pipeline project including the sale of the St. Clair Line will be cancelled.

LIQUIDITY AND CAPITAL RESOURCES

We manage cash to maximize value while assuring appropriate amounts of cash are available, as required. We invest our available cash in high-quality money market securities. Such money market securities are designed for the safety of principal and for liquidity, and accordingly do not include equity-based securities.

We meet our short-term cash requirements through funds generated from operations, the utilization of loans from Westcoast, and the issuance of commercial paper. Long-term capital requirements for expansion, maintenance and investments are met through the combination of cash flow from operations, issuance of long-term debt and preference shares.

Changes in Cash Flow

	For The Years Ended December 31	
($millions)	**2010**	2009
Operating activities	**174**	642
Investing activities	**(232)**	(247)
Financing activities	**36**	(361)

Operating Activities

Union Gas' heating season extends from approximately November through March. We begin the heating season with near-capacity natural gas inventory levels which are drawn throughout the heating season. Inventory levels decrease from December and thus contribute to a positive cash flow from operations during the first quarter. 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.

Some of our customers purchase gas directly from marketers. Marketers typically deliver gas to us evenly throughout the year, whereas most of their customers use gas based on seasonality. As part of our normal billing process, we bill the marketers' customers as gas is used and remit this cash to the marketer when gas is delivered to us. Therefore, during the first and fourth quarters of the year, customers typically use more gas than is delivered to us and we collect cash from the marketers' customers creating a positive cash flow. During the second and third quarters, marketers deliver more gas than their customers use, thus creating a significant cash outflow. These are normal seasonal trends.

The primary factors impacting cash flow from operations for 2010 compared to 2009 include lower collections due to a lower spread between commodity rates charged to customers and actual gas costs, higher refunds to customers of over collection of commodity costs in 2009, and a large final payment of 2009 taxes made in the first quarter of 2010.

Investing Activities

The table below is a summary of capital expenditures:

	For The Years Ended December 31		
	2011	2010	2009
	(estimated)		
Storage and transmission projects	36%	25%	32%
Distribution	50%	59%	57%
General equipment	14%	16%	11%
	100%	100%	100%
Total capital expenditure ($millions)	$305	$232	$247

The table below is a summary of capital project type:

	For The Years Ended December 31		
	2011	2010	2009
	(estimated)		
Maintenance projects[5]	92%	97%	92%
Expansion projects	8%	3%	8%
	100%	100%	100%

Capital expenditures for 2010 were lower compared to 2009 due primarily to expansion and maintenance projects that were not completed in 2010 as planned or were deferred to 2011. Maintenance and expansion expenditures for 2011 are expected to be higher than the 2010 level of spending. The 2011 expansion capital expenditures reflect our continued assessment of the timing of projected long-term market requirements and general economic conditions. Based on our current assessment, we believe that expansion opportunities will continue to exist in the future.

As outlined in the financing activities discussion that follows, we have sufficient financing available to meet our investing requirements. Management expects that financing of 2011 projects will be done through a combination of cash generated from operations and available debt facilities.

Financing Activities

We have the following financing arrangements in place:

- In September 2010, Union Gas renewed its shelf prospectus. The shelf prospectus permits the issuance of medium-term notes, in one or more series, up to an aggregate principal amount of $500 million and for terms as covered in the pricing supplement at the time of issue with maturities of not less than one year from the date of issue. The shelf will expire in October 2012. As of December 31, 2010, $500 million was available.
    - In June 2010, we retired, at par, $185 million of Series 2 medium-term note debenture at 7.20% per annum.
    - In July 2010, under our previous shelf prospectus, we issued $250 million of medium-term note debentures at 5.20% per annum, due July 23, 2040.
    - In October 2010, we retired, at par, $37 million of 1988 Series 2 sinking fund debentures at 7.20% per annum.
- Union Gas has a $500 million committed credit facility available to help meet its short-term financing needs. As of December 31, 2010, $343 million was available.
    - Our $500 million committed credit facility expires in July 2012 and includes a provision which requires us to repay all borrowings under the facility for a period of two days during the second quarter of each year. This facility is intended to be used primarily to manage the significant changes in working capital experienced by Union Gas as a result of volumes and prices associated with natural gas purchases and sales. Most of the short-term cash requirements are funded through issuing commercial paper at rates generally below the lender's prime rate. Our 2010 commercial paper peaked in June at approximately $232 million.
- In July 2010, Union Gas cancelled the $15 million credit facility and the $1 million remaining letters of credit issued under the facility were moved to a credit facility of our parent, Spectra Energy Corp.

[5] Maintenance projects include costs incurred for new customer attachments. Maintenance projects also include expansion capital for in-franchise customers.

In order to maintain the common equity component of the capital structure at a level no greater than that approved by the OEB, we typically pay a quarterly dividend to our parent company. During 2010, we paid a quarterly dividend to our parent of approximately $16 million (2009 – approximately $16 million in first three quarters). In December 2010, we paid an additional $125 million dividend to our parent (2009 – $116 million paid in first quarter of 2010).

OUTSTANDING SHARES

	December 31 2010	December 31 2009
Redeemable Preference Shares		
Class A, Series A, 5.5%	**47,672**	47,672
Class A, Series C, 5.0%	**49,500**	49,500
Preference Shares		
Class A, Series B, 6.0%	**90,000**	90,000
Class B, Series 10, 4.88%	**4,000,000**	4,000,000
Common Shares	**57,822,650**	57,822,650

FINANCIAL CONDITION

Ratings Summary

	Standard & Poor's	**DBRS**
Commercial paper	A – 1 (low)[6]	R – 1 (low)
Debentures	BBB+	A
Preference shares	P – 2 (low)[7]	Pfd – 2

Our credit ratings remain unchanged from those reported in the 2009 Annual Report.

The above credit ratings are dependent upon, among other factors, the ability to generate sufficient cash to fund capital and investment expenditures, our results of operations, market conditions and other factors. Our credit ratings could impact our ability to raise capital in the future, impact the cost of our capital and, as a result, have an impact on our liquidity.

[6] Represents Canadian National Scale Commercial Paper Rating.
[7] Represents Canadian Preferred Stock Rating.

CONTRACTUAL OBLIGATIONS

The table below is a summary of our contractual payment obligations, due by period.

($millions)	Total	2011	2012-2013	2014-2015	Thereafter
Long-term debt	2,240	250	–	300	1,690
Redeemable preference shares	5	–	–	–	5
Operating leases	26	5	10	10	1
Purchase obligations[8]	1,038	510	209	192	127
Environmental obligations[9]	95	39	45	5	6
Contributions to employee future benefit plan[10]	46	46	–	–	–
Total contractual obligations[11]	3,450	850	264	507	1,829

RELATED PARTY TRANSACTIONS

We purchase gas, storage and transportation services at prevailing market prices and under normal trade terms from related parties. During the year ended December 31, 2010, these purchases totalled $11 million (2009 – $6 million). Union Gas also provides storage and transportation services to related parties which totalled $1 million during 2010 (2009 – $1 million).

We provided administrative, management and other services to related parties totalling $10 million (2009 – $9 million), which were billed and recovered at cost. Charges from related parties for administrative and other goods and services were $9 million (2009 – $7 million).

At December 31, 2010 we have receivable balances of $2 million (2009 – $6 million) and payable balances of $3 million (2009 – $6 million) with related parties, all of which are recorded in accounts receivable and accounts payable, respectively.

During 2010, we obtained from and provided unsecured loans to Westcoast. The balance outstanding on these loans at December 31, 2010 was a $198 million payable (2009 – $6 million receivable). These loans are classified as short-term borrowings in 2010. Interest received on these loans during 2010 totalled less than $1 million (2009 – less than $1 million) and interest paid on these loans totalled less than $1 million (2009 – less than $1 million). Interest on these loans is calculated based on the monthly average of 30-day banker's acceptance rates.

[8] Includes: firm capacity payments that provide us with uninterrupted firm access to natural gas transportation and storage; contractual obligations to purchase physical quantities of natural gas; contracts for software and consulting or advisory services; contractual obligations for engineering, procurement and construction costs for pipeline projects.

[9] Includes capital, operating and maintenance expenditures related to the comprehensive certificate of approval.

[10] We are unable to reasonably estimate employee future benefit plan contributions beyond 2011 due primarily to uncertainties about market performance of plan assets.

[11] Excludes cash obligations for asset retirement activities. The amount of cash flows to be paid to settle the asset retirement obligations is not known with certainty as Union Gas may use internal resources or external resources to perform retirement activities. Amounts also exclude reserves for litigation, environmental remediation, annual insurance premiums that are necessary to operate the business and regulatory liabilities because Union Gas is uncertain as to the amount and/or timing of when cash payments will be required. Also, amounts exclude future income taxes and investment tax credits on the Consolidated Balance Sheets since cash payments for income taxes are determined based primarily on taxable income for each discrete fiscal year.

GAS SUPPLY

The gas supply portfolio of Union Gas primarily includes contracts with pricing mechanisms that reflect monthly and daily variations in the price of gas. These contracts are indexed to either the New York Mercantile Exchange natural gas futures contracts, the Canadian Gas Price Reporter that publishes Alberta index prices or the Platt's Inside FERC Dawn Monthly Index.

Union Gas continues to monitor and evaluate the new and changing natural gas supply dynamics to determine what opportunities exist for Union Gas' customers. Union Gas has contracted for upstream transportation capacity to move new supplies to Ontario, including new supply sources based in the U.S. Rocky Mountains and U.S. southern shale supply areas. These new supplies began arriving in the Union Gas system on November 1, 2010. Union Gas has also taken steps to allow for the emerging Marcellus Shale gas supplies to serve its Ontario system customers beginning in 2012, including contracting for firm transportation capacity on other pipelines to facilitate moving this supply to Dawn and ultimately to our customers.

OUTLOOK

Gas Sales and Distribution

The significant increase in North American gas supply production coupled with moderate demand caused by the effects of the recent economic recession, resulted in low natural gas prices and low volatility in 2010. This trend is expected to continue in 2011. Despite low natural gas prices, the growth in demand for natural gas in our residential, commercial and industrial markets is expected to remain flat, however demand growth is expected from natural gas fired power generation.

Union Gas is experiencing a reduction in distribution throughput as a result of energy conservation due to our Demand Side Management (DSM) initiatives, declining normalized use per customer and a general trend toward warmer weather. We expect these trends to continue. In addition, the Ontario Ministry of Energy is continuing their commitment to aggressively promote a culture of conservation across the province that is expected to further reduce energy consumption, with corresponding impacts on our volume-based revenue.

Union Gas continues to support focused efforts to promote conservation and energy efficiency through our DSM programs. In each of 2009 and 2010, we spent $22 million promoting these programs with an increase in spending planned in 2011. In view of the significant efforts to build a culture of conservation in Ontario, we expect customers to continue to focus on reducing gas consumption by increasing investments in energy efficiency and conservation.

In May 2009, the Ontario Legislature passed the *Ontario Green Energy and Green Economy Act*, an Act to help transform the Ontario energy sector towards a culture of conservation and to encourage the development of renewable energy throughout the province. We will continue to monitor the legislation and we do not anticipate any material impact at this time.

Storage and Transportation

The storage and transportation marketplace continues to deal with the global economic slowdown but is expected to be stable going forward. Weak commodity prices as a result of a more robust North American gas supply balance and narrower seasonal price spreads in the marketplace are expected to result in lower unregulated storage values. North American natural gas supplies continue to increase as result of new supply attachment including liquefied natural gas (LNG) and development in the U.S. Rocky Mountains, as well as various new shale gas resource projects such as the Barnett, Fayetteville, Woodford and the Marcellus Shale areas. The development of these new resources has increased overall North American gas supply reserves and is leading to significant new pipeline and storage infrastructure to connect these new supplies to the North American pipeline grid and the associated natural gas consuming market areas. These new supply sources will be available to serve Ontario and Eastern Canadian markets. Furthermore, we are experiencing a change in traditional natural gas flow patterns as these new supplies continue to develop. This will continue to provide Union Gas opportunities and challenges for new storage and pipeline infrastructure projects. Union Gas applied to the OEB, during 2010, for multiple transportation service enhancements to respond to these changing flow patterns. These services were approved by the OEB and will enhance access to emerging supply basins and provide enhanced flexibility to attract gas to Dawn, where it can be stored and delivered to downstream eastern markets.

The location of our storage and transportation facilities, with interconnections between major U.S. markets in the Great Lakes region and the U.S. Northeast continues to support long-term growth opportunities for us. It is our expectation that demand for natural gas in North America will continue to grow at a long-term rate of one percent per year along with continued growth in peak day demands.

Storage Project Developments

During 2010, Union Gas completed the drilling of additional storage wells in the Tipperary North and South storage reservoirs. These new wells were operational in 2010.

In June 2010, Union Gas purchased a depleted gas reservoir in the Municipality of Chatham-Kent from Torque Energy Inc. and Liberty Oil & Gas Ltd. A test well was completed in the reservoir in the fall of 2010 with favourable results. Senior Management approval to proceed with the project was provided in October 2010 with the application for OEB approval of the project filed in January 2011.

Environmental, Health and Safety

During 2008, we obtained approval from the Ontario Ministry of the Environment (MOE) for a multi-site comprehensive certificate of approval (CC of A) for the permitting of our air and noise emission sources. The CC of A will treat Union Gas as a single integrated natural gas storage, transmission and distribution system incorporating all storage pools, metering and regulating stations, compressor stations and buildings into a single environmental permit. The terms and conditions of the CC of A include significant financial obligations for capital, operating and maintenance expenditures over a period of approximately 10 years, and the total estimated obligation has been included in the Contractual Obligations section of this document. Under the terms of the CC of A, we will be allowed to add and modify facilities without prior approval from the MOE, thereby reducing the risk of delays associated with obtaining environmental permits. Union Gas remains on target to meet the current 10 year plan.

In 2010, the MOE confirmed Union Gas's third party audit plan. The purpose of the audits is to confirm that our facilities are operating in accordance with the conditions specified in the CC of A. In November 2010, the Parkway and Dawn compressor station sites were audited with no major findings. Furthermore, the MOE has also confirmed the 2011 audit schedule which will include the Hagar LNG Plant and the Waubuno and Bickford/Sombra Storage Pool Sites.

Union Gas has been notified that a Workwell audit will be conducted in the second quarter of 2011. Workwell is a health and safety management audit conducted by the Workplace Safety and Insurance Board. The Workwell audit is occurring as a result of an employee vehicle fatality in late 2009. We do not anticipate any material impact at this time.

Global Climate Change

Policymakers at provincial, federal and international levels continue to evaluate potential legislative and regulatory compliance mechanisms to achieve reductions in global greenhouse gas (GHG) emissions in an effort to address the challenge of climate change. It is likely that our assets and operations are or will become subject to direct and indirect effects of current and possible future global climate change regulatory actions in the jurisdictions in which those assets and operations are located. See Risk Factors – Global Climate Change Risk for further discussion.

RISK FACTORS

Our earnings are affected by the risks inherent in the natural gas industry and energy marketplace. In general, our business and 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, the absolute and relative price of alternative energy sources, foreign exchange rates and global competition. In 2011, we expect that the North American economy will continue to remain sluggish.

Sales to Union Gas' 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, and the continued shift to higher efficiency. New customer additions increased slightly in 2010, but are expected to remain moderate in 2011. In 2011, the ongoing trend towards energy efficiency will continue to put pressure on usage.

A large quantity of our transportation capacity is now subject to renewal on an annual basis. Our standard contract terms provide automatic renewal of contracts, after the initial term, for one year at a time unless the customer provides two years prior notice of termination. For storage contracts, our standard contract terms do not allow for renewals but will typically have contract terms of one to five years. Due to changing gas supply patterns and as expected, one of our customers gave us notice in 2009 for transportation turnback starting in late 2011, and gave us notice in 2010 for additional turnback commencing in late 2012. This turnback was for capacity on our system that ultimately supplied the U.S. northeast by way of the customer's third party pipeline. This turned back capacity will be used to help satisfy increased demands to move gas from Dawn to points further east and north in Ontario and Quebec.

Commodity Price Risk

Fluctuations in natural gas prices affect our gas purchase costs for our own operating requirements as well as for the gas supply costs we incur for and collect from our system customers. Our gas procurement policy primarily includes contracts with pricing mechanisms that reflect monthly and daily variations in the price of gas. 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 we could incur if a counterparty fails to perform under its contractual obligations. We analyze the customer's financial condition prior to entering into an agreement, obtain collateral when appropriate, establish credit limits and monitor the appropriateness of those limits on an ongoing basis.

Our credit exposure consists of both the risk of collecting receivables for services provided as well as the risk related to gas imbalances that occur as a regular part of the services provided in both the direct purchase market and ex-franchise market.

In the normal course of operations, we provide gas loans to other parties from our holdings of gas in storage. The replacement cost of the gas on loan at December 31, 2010 was $72 million (2009 - $39 million). We manage our credit exposure related to gas loans by subjecting these parties to the same credit policies used for all customers.

Weather Risk

As a primary component of Union Gas rates is volume based, the revenue levels approved by the OEB are impacted by weather. 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 2008 and beyond. Since a large portion of the gas distributed to the residential and commercial markets 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 on our financial results.

Regulatory Risk

Our natural gas assets and operations are subject to regulation by federal, provincial and local authorities including the OEB and by various federal and provincial authorities under environmental laws. Regulation affects almost every aspect of our business, including the ability to determine terms and rates for services provided by some of our businesses, acquisitions, construction, expansion and operation of facilities, issuance of equity or debt securities, and dividend payments.

In addition, regulators in Canada have taken actions to strengthen market forces in the gas pipeline industry, which have led to increased competition. In a number of key markets, natural gas pipeline and storage operators are facing competitive pressure from a number of new industry participants, such as alternative suppliers as well as traditional pipeline competitors. Increased competition driven by regulatory changes could have a material effect on our business, earnings, financial condition and cash flows.

Competition Risk

As our distribution business is regulated by the OEB, it is generally not subject to third-party competition within our distribution franchise area. However, as a result of a 2006 decision by the OEB, physical bypass of newly-required facilities even within our distribution franchise area may be permitted. In addition, other companies could enter our markets or regulations could change.

Union Gas competes with other forms of energy available to its customers and end-users, including electricity, coal, propane and fuel oils. Factors that influence the demand for natural gas include price changes, the availability of natural gas and other forms of energy, the level of business activity, conservation, legislation, governmental regulations, the ability to convert to alternative fuels, weather and other factors.

Storage Market Risk

We have market based rates for some of our storage capacity which are based largely on seasonal natural gas market pricing spreads. To the extent that seasonal natural gas market pricing spreads deviate from historical norms or there is significant growth in the amount of storage capacity available to natural gas markets relative to demand, our approach to managing our market-based storage capacity may not protect us from significant variations in storage revenues.

Permit Fees Risk

Effective January 1, 2007, the Government of Ontario granted municipalities the right to charge a fee to recover the costs of issuing a permit to access pipelines located within a municipal roadway. During 2010, permit fees levied by municipalities against Union Gas did not have a significant impact on our consolidated financial statements. Should more municipalities start implementing a permit fee or if the amounts increase and these assessments become significant in the future, Union Gas will apply to the OEB to recover the annual cost of these fees in rates.

Financing Risk

Our business is financed to a large degree through debt. The maturity and repayment profile of debt used to finance investments often does not correlate to cash flows from assets. Accordingly, we rely on access to both short-term and long-term capital markets as a source of liquidity for capital requirements not satisfied by the cash flow from operations and to fund investments originally financed through debt. Our long-term debt is currently rated investment-grade by various rating agencies. If the rating agencies were to rate us below investment-grade, our borrowing costs would increase, perhaps significantly. In addition, we would likely be required to pay a higher interest rate in future financings, and our potential pool of investors and funding sources could decrease.

We are subject to long-term debt covenants that include a limitation on the payment of dividends, and requirements for specific interest coverage ratios prior to the issuance of additional long-term debt. Although we do not anticipate any impact to our current financing plans, reduced earnings may limit the payment of future dividends and the level of new long-term debt available to us. We maintain a revolving credit facility to backstop our commercial paper programs for short-term borrowings. This facility includes a financial covenant which limits the amount of debt that can be outstanding as a percentage of total capital. Failure to maintain this covenant could preclude us from issuing commercial paper or borrowing under the revolving credit facility and could require immediate pay down of any outstanding drawn amounts under other revolving credit agreements, which could adversely affect our cash flow.

If we are not able to access capital at competitive rates, our ability to finance operations and implement our strategy may be adversely affected. Restrictions on our ability to access financial markets may also affect our ability to execute our business plan as scheduled. An inability to access capital may limit our ability to pursue improvements or acquisitions that we may otherwise rely on for future growth. Any downgrade or other event negatively affecting the credit ratings could make our costs of borrowing higher or access to funding sources more limited.

Human Resources Risk

Union Gas' workforce consists of both unionized and non-unionized employees. Labour disruptions associated with the collective bargaining process can affect our ongoing operations. Projected changes in workforce demographics and a future shortage of skilled trades represent an issue that is being addressed by Union Gas.

Performance Risk

We have 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 and partners may increase the severity of a default.

Litigation Risk

Union Gas, in the course of its operations, is subject to environmental and other claims, lawsuits and contingencies. Although it is possible that liabilities may be incurred in instances for which no accruals have been made, we have no reason to believe that the ultimate outcome of such matters currently known to us could have a material effect on our consolidated financial statements.

Facility Risk

We carry 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 Government is operating with large deficits and significant spending commitments, in particular with commitments regarding their poverty agenda. As such it is expected that they will continue to search for new sources of revenues including non-tax revenue streams such as fees and levies. The Ontario Government also has a history of direct intervention in energy matters in the publicly owned electricity sector. This has been increasing in recent years and the risk is that the Ontario Government will intervene on the privately owned natural gas sector, some of which might affect Union Gas.

Environmental, Health and Safety Risk

There are a variety of hazards and operating risks inherent in natural gas storage, transmission, and distribution activities, such as leaks, explosions and mechanical problems that could cause substantial financial losses. In addition, these risks could result in significant injury, loss of human life, significant damage to property, environmental pollution and impairment of operations, any of which could result in substantial losses. For pipeline and storage assets located near populated areas, including residential areas, commercial business centers, industrial sites and other public gathering areas, the level of damage resulting from these risks could be greater. We do not maintain insurance coverage against all of these risks and losses, and any insurance coverage we might maintain may not fully cover the damages caused by those risks and losses. Therefore, should any of these risks materialize, it could have a material adverse effect on our business, earnings, financial condition and cash flows.

Global Climate Change Risk

The current international climate framework, the United Nations-sponsored Kyoto Protocol, prescribes specific targets to reduce GHG emissions for developed countries for the 2008-2012 periods. United Nations-sponsored international negotiations were held in Copenhagen, Denmark in December 2009 and in Cancun, Mexico in December 2010 with the intent of defining a future agreement for 2012 and beyond. While the talks resulted in a non-binding political agreement, to date, a binding successor accord to the Kyoto Protocol has not been realized.

While Canada is a signatory to the Kyoto Protocol, the Canadian federal government has confirmed it will not achieve the targets within the timeframes specified. Instead, the government in 2008 outlined a regulatory framework mandating GHG reductions from large final emitters. Regulatory design details from the Government of Canada remain forthcoming. However, Canada has reaffirmed its strong preference for a harmonized approach with that of the U.S. Regardless of the timing, we expect a number of our assets and operations will be affected by pending federal climate change regulations. However, the materiality of any potential compliance costs is unknown at this time as the final form of the regulation and compliance options has yet to be determined by policymakers.

A number of provinces are establishing or considering provincial or regional programs that would mandate reductions in GHG emissions including Ontario which is a member of the Western Climate Initiative which also includes the provinces of British Columbia, Manitoba and Quebec. However, the key details of future GHG restrictions and compliance mechanisms remain largely undefined.

Due to the uncertainty of Canadian federal and provincial policies, we cannot estimate the potential effect of proposed GHG policies on our future consolidated results of operations, financial position or cash flows. However such legislation could increase our operating costs materially, require material capital expenditures or create additional permitting, which could delay proposed construction projects.

Protecting Against Potential Terrorist Activities

The potential for terrorism because of the high profile of the natural gas industry has subjected our operations to increased risks that could have a material adverse effect on our business. This risk is particularly great for companies, like ours, operating in any energy infrastructure industry that handles volatile gaseous and liquid hydrocarbons. The potential for terrorism has subjected our operations to increased risks that could have a material adverse effect on our business. In particular, we may experience increased capital and operating costs to implement increased security for our facilities and pipelines, such as additional physical facility and pipeline security and additional security personnel. Moreover, any physical damage to high profile facilities resulting from acts of terrorism may not be covered, or covered fully, by insurance. We may be required to expend material amounts of capital to repair any facilities, the expenditure of which could adversely affect our cash flows and business.

Changes in the insurance markets attributable to terrorist attacks may make certain types of insurance more difficult for us to obtain. Moreover, the insurance that may be available to us may be significantly more expensive than our existing insurance coverage. Instability in the financial markets as a result of terrorism or war could also affect our ability to raise capital.

Pension Risk

Our costs of providing defined benefit pension plans are dependent upon a number of factors, such as the rates of return on plan assets, discount rates used to measure pension liabilities, actuarial gains and losses, future government regulation and our contributions made to the plans. Without sustained growth in the pension plan investments over time to increase the value of our plan assets, and depending upon the other factors impacting our costs as listed above, we could experience net asset, expense and funding volatility. This volatility could have a material effect on our earnings and cash flows.

Land Rights

Certain aboriginal groups in Ontario have also claimed aboriginal and treaty rights in areas where Union Gas' Dawn storage and transmission assets are located and also in areas where the Dawn-Trafalgar pipeline route is located. The existence of these claims could give rise to future uncertainty regarding land tenure depending upon their negotiated outcome.

CERTIFICATION OF DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

Disclosure Controls and Procedures

Disclosure controls and procedures are controls and other procedures that are designed to: (a) provide reasonable assurance that material information required to be disclosed by us is accumulated and communicated to management to allow timely decisions regarding required disclosure; and (b) ensure that material information required to be disclosed by us is recorded, processed, summarized, and reported within the time periods specified in applicable securities legislation.

Our management, with the participation of the President and the Chief Financial Officer, has evaluated the effectiveness of our disclosure controls and procedures as of December 31, 2010, and, based upon this evaluation, the President and the Chief Financial Officer have concluded that these disclosure controls and procedures, as defined by the Companion Policy 52-109CP to National Instrument 52-109, *Certification of Disclosure in Issuers' Annual and Interim Filings (NI 52-109)*, are effective for the purposes set out above.

Internal Control over Financial Reporting

Our management is responsible for designing, establishing and maintaining an adequate system of internal control over financial reporting. Our internal control system was designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes, in accordance with Canadian GAAP. Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with policies and procedures may deteriorate.

Our management, with the participation of our President and the Chief Financial Officer, has conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2010 based on the framework in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on that evaluation, management concluded that our internal control over financial reporting, as defined by the Companion Policy 52-109CP to NI 52-109, is effective to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements in accordance with Canadian GAAP.

Changes in Internal Control over Financial Reporting

Under the supervision and with the participation of management, including the President and Chief Financial Officer, we have evaluated changes in internal control over financial reporting that occurred during the fiscal quarter and year ended December 31, 2010 and found no change that has materially affected, or is reasonably likely to materially affect, internal control over financial reporting.

Our Board of Directors reviewed and approved the 2010 audited consolidated financial statements and this management's discussion and analysis prior to its release.

CRITICAL ACCOUNTING POLICIES & ESTIMATES

The application of accounting policies and estimates is an important process that continues to evolve as Union Gas' operations change and accounting guidance is issued. Union Gas has identified a number of critical accounting policies and estimates that require the use of significant estimates and judgments.

Management bases its estimates and judgments on historical experience and on other various assumptions that they believe are reasonable at the time of application. The estimates and judgments may change as time passes and more information becomes available. If estimates and judgments are different than the actual amounts recorded, adjustments are made in subsequent periods to take into consideration the new information. Union Gas discusses its critical accounting policies and estimates and other significant accounting policies with senior members of management and the Board of Directors.

Regulatory Accounting

Union Gas follows Canadian GAAP, which allows accounting treatments that may differ for rate-regulated operations from those otherwise expected in non rate-regulated businesses. As a result, we record assets and liabilities that result from the regulated ratemaking process that may not be recorded under GAAP for non rate-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 ratepayers. 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 rate-regulated entities. Management believes the existing regulatory assets are probable of recovery. This determination reflects the current political and regulatory climate and is subject to change in the future. If future recovery of costs ceases to be probable, asset write-offs could be required to be recognized in current period earnings.

Unbilled Revenue

Revenues from the transportation, storage, distribution and sales of natural gas are recognized when either the service is provided or the product is delivered. Revenues related to these services provided or products delivered but not yet billed are estimated each month. Gas sales and distribution revenue and cost of gas are 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 and historical consumption per heating degree-day. Unbilled revenue recorded at December 31, 2010 was $118 million (2009 – $100 million). Differences between actual and estimated unbilled revenues are not material to net income. Included in unbilled revenue are natural gas costs passed through to customers without a mark-up. At December 31, 2010 $73 million (2009 – $54 million) was included in unbilled revenue for the cost of natural gas.

Employee Future Benefits

Critical estimates and assumptions relating to our defined benefit pension plans are required to account for employee future benefits. Changes to these estimates and assumptions could result in a material difference to our employee future benefit plan obligation.

The following is a summary of the sensitivity of key assumptions used to record the employee future benefit liability:

Sensitivity of key assumptions

($millions)	**Registered Pension Plan and Supplemental Pension Arrangements**		**Post-Retirement Benefits Other than Pensions**	
Assumed change in:	**1% Increase**	**1% Decrease**	**1% Increase**	**1% Decrease**
Discount rate				
Change in 2010 net periodic benefit cost	**(7)**	7	**(1)**	1
Change in benefit obligation	**(72)**	81	**(9)**	10
Health care cost trend rate				
Change in 2010 net periodic benefit cost	**N/A**	N/A	**1**	(1)
Change in benefit obligation	**N/A**	N/A	**6**	(6)
Expected rate of return on assets				
Change in 2010 net periodic benefit cost	**(5)**	5	**N/A**	N/A

FUTURE ACCOUNTING CHANGES

Transition to International Financial Reporting Standards (IFRS)

In February 2008, the Accounting Standards Board (AcSB) of the Canadian Institute of Chartered Accountants (CICA) confirmed that publicly accountable enterprises will be required to adopt IFRS in place of GAAP for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011.

In September, 2010, the AcSB offered an optional one year deferral to adopt IFRS for qualifying entities with rate regulated activities and permit such entities to continue to apply Part V – Pre changeover accounting standards of the CICA Handbook during that period. The Company is a qualifying entity for purposes of this deferral.

While the Company's IFRS conversion project was on track to meet the original conversion deadline, we have elected to use the deferral offered by the AcSB. This decision was made to allow us to convert at the same time as many companies in our industry, and to review our reporting options, including registering with the Securities and Exchange Commission (SEC) of the United States, so that we could report under U.S. GAAP instead of IFRS.

At this time, it is the Company's intention to take the steps necessary to report under U.S. GAAP starting in 2012.

The consolidated financial statements and all information in this report have been prepared by and are the responsibility of management. The consolidated 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 Union Gas' 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 fulfils its responsibility for financial reporting and for final approval of the consolidated financial statements.

The Board of Directors meets regularly with management, the internal auditors and the shareholders' auditors to review the consolidated financial statements, the Independent Auditor's 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 Board of Directors, as does the Director of Internal Audit Services.

Deloitte & Touche LLP performed an independent audit of the 2010 and 2009 consolidated financial statements in this report. Their independent professional opinion on the fairness of these consolidated financial statements is included in the Independent Auditor's Report.

March 16, 2011

Julie Dill	J. Patrick Reddy
President	Chief Financial Officer

Deloitte.

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Independent Auditor's Report

To the Shareholders of
Union Gas Limited

We have audited the accompanying consolidated financial statements of Union Gas Limited, which comprise the consolidated balance sheets as at December 31, 2010 and December 31, 2009, and the consolidated statements of income and comprehensive income, retained earnings, and cash flows for the years then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Union Gas Limited as at December 31, 2010 and December 31, 2009 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
Licensed Public Accountants
March 16, 2011

UNION GAS LIMITED
Consolidated Statements of Income and Comprehensive Income

For the Years Ended December 31 ($millions)	**2010**	2009
Gas sales and distribution revenue	**1,493**	1,684
Cost of gas (note 15)	**794**	1,026
Gas distribution margin	**699**	658
Storage and transportation revenue (note 15)	**308**	299
Other revenue	**29**	36
	1,036	993
Expenses		
Operating and maintenance (note 15)	**364**	345
Depreciation and amortization (note 5)	**200**	195
Property and capital taxes	**67**	68
	631	608
Income before other items	**405**	385
Other (income) and expenses, net	**–**	2
Income before interest and income taxes	**405**	383
Interest expense (notes 6 and 15)	**158**	160
Income before income taxes	**247**	223
Income taxes (note 14)	**41**	48
Net income and comprehensive income	**206**	175
Preference share dividends	**2**	2
Net income applicable to common shares	**204**	173

(*See accompanying notes)*

UNION GAS LIMITED
Consolidated Statements of Retained Earnings

For the Years Ended December 31 ($millions)	**2010**	2009
Retained earnings, beginning of year	**696**	688
Net income and comprehensive income	**206**	175
Dividends		
Preference shares	**(2)**	(2)
Common shares	**(190)**	(165)
Retained earnings, end of year	**710**	696

(*See accompanying notes)*

UNION GAS LIMITED
Consolidated Balance Sheets

As at December 31 ($millions)	**2010**	2009
Assets		
Current assets		
Cash and cash equivalents	**12**	34
Accounts receivable (notes 3 and 15)	**516**	401
Inventories (note 4)	**174**	224
Future income taxes (note 14)	**14**	57
Total current assets	**716**	716
Property, plant and equipment (note 5)		
Cost	**6,370**	6,187
Accumulated depreciation	**1,994**	1,884
Net property, plant and equipment	**4,376**	4,303
Regulatory and other assets (note 13)	**493**	427
Total Assets	**5,585**	5,446
Liabilities and Shareholders' Equity		
Current liabilities		
Short-term borrowings (note 15)	**198**	–
Commercial paper (note 6)	**157**	39
Accounts payable and accrued charges (notes 3 and 15)	**582**	794
Income taxes payable (note 14)	**8**	79
Long-term debt (note 6)	**250**	222
Total current liabilities	**1,195**	1,134
Long-term liabilities		
Long-term debt (note 6)	**1,978**	1,979
Mandatorily redeemable preference shares (note 7)	**5**	5
Future income taxes (note 14)	**361**	327
Asset retirement obligations (note 9)	**123**	108
Regulatory and other liabilities (note 13)	**472**	455
Total long-term liabilities	**2,939**	2,874
Total Liabilities	**4,134**	4,008
Non-controlling interest	**9**	10
Shareholders' equity		
Share capital (note 8)	**732**	732
Retained earnings	**710**	696
Total Shareholders' Equity	**1,442**	1,428
Total Liabilities and Shareholders' Equity	**5,585**	5,446

(See accompanying notes)

Approved by the Board

Director Director

UNION GAS LIMITED
Consolidated Statements of Cash Flows

For the Years Ended December 31 ($millions)	**2010**	2009
Operating Activities		
Net income	**206**	175
Items not affecting cash		
Depreciation and amortization	**200**	195
Future income taxes	**25**	(55)
Changes in working capital		
Accounts receivable	**(42)**	167
Inventories	**32**	26
Account payables, accrued charges and other	**(247)**	134
	174	642
Investing Activities		
Capital expenditures	**(232)**	(247)
Financing Activities		
Net increase (decrease) in short-term borrowings	**198**	(115)
Net increase (decrease) in commercial paper	**118**	(167)
Long-term debt issued	**250**	–
Long-term debt repayments	**(222)**	(29)
Dividends paid	**(308)**	(50)
	36	(361)
Change in cash and cash equivalents, during the year	**(22)**	34
Cash and cash equivalents, beginning of year	**34**	–
Cash and cash equivalents, end of year	**12**	34
Supplementary Disclosure of Cash Flow Information:		
Cash payments of interest	**152**	164
Cash payments of income taxes	**96**	47

(See accompanying notes)

UNION GAS LIMITED
Notes to Consolidated Financial Statements
December 31, 2010 and 2009

Union Gas Limited (Union Gas or 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 market participants. 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 approximately 5,000 kilometres of high-pressure transmission pipeline and approximately 60,600 kilometres of distribution main and service pipelines. The Company's underground natural gas storage facilities have a working capacity of more than 155 billion cubic feet (Bcf).

1. Significant Accounting Policies

Accounting Principles

The consolidated financial statements of the Company have been prepared in accordance with Canadian generally accepted accounting principles (GAAP) and certain transactions have been recorded using accounting principles for rate-regulated enterprises as discussed below under "Regulation." 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, income tax expense, employee future benefit expense, estimated useful life of property, plant and equipment and asset retirement obligations.

Accounting Changes

Rate-regulated Operations

Effective January 1, 2009, amendments have been made to certain sections of the Canadian Institute of Chartered Accountants (CICA) Handbook related to rate-regulated accounting.

CICA Section 3465, Income Taxes has been amended to require rate-regulated enterprises to recognize future income tax assets and liabilities. This amendment also requires that a regulatory asset or liability for the amount of future income taxes expected to be recovered from or refunded to ratepayers, and to present these amounts on a pre-tax basis in the financial statements. The impact of these changes resulted in an increase in regulatory and other assets and an increase in future income tax liabilities of $273 million on January 1, 2009.

CICA Section 1100, Generally Accepted Accounting Principles has been amended to remove a temporary exemption pertaining to the application of the recognition and measurement of assets and liabilities arising from rate regulation. In the absence of specific guidance the CICA has permitted reliance on another source of GAAP, specifically the Statement of Financial Accounting Standards No. 71, *Accounting for the Effects of Certain Types of Regulation* (FAS 71). Since FAS 71 does not specifically address depreciation methods, Statement of Financial Accounting Standards No. 143, *Accounting for Asset Retirement Obligations* (FAS 143) applies to entities that meet FAS 71. FAS 143 requires asset removal costs to be reported as a regulatory liability. Prior to 2009, asset removal costs were included in property, plant and equipment. This reclassification resulted in an increase in property, plant and equipment and an increase in regulatory liabilities of $402 million on January 1, 2009.

Principles of Consolidation

The consolidated financial statements of the Company include the accounts of Union Gas and its subsidiary, Huron Tipperary Limited Partnership I, of which the Company owns 75%.

Regulation

The Company is regulated by the Ontario Energy Board (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, with the exception of the items noted below, system expansion or facility abandonment, adequacy of service, public safety aspects of pipeline system construction and certain accounting principles. The OEB has determined that it will forbear from regulating the prices for long-term storage services. The Storage Forbearance Decision created an unregulated storage operation within Union Gas and provides the framework required to support new storage investments.

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 its ability to achieve forecast revenues and manage costs.

Rates effective January 1, 2007 were approved by the OEB on the basis of the traditional cost of service framework. Effective January 1, 2008, the Company began a five year incentive regulation term. The incentive regulation framework establishes new rates at the beginning of each year through the use of a pricing formula rather than through the examination of revenue and cost forecasts. The Company is expecting to set rates for 2013 on a cost of service basis.

The Company follows Canadian GAAP, which may differ for regulated operations from those otherwise expected in non rate-regulated businesses. As a result, the Company records assets and liabilities that result from the regulated ratemaking process that may not be recorded under GAAP for non rate-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, or for certain net revenues beyond a pre-established threshold. 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 could be recognized in current period earnings.

Revenue Recognition

Revenues from the transportation, storage, distribution and sales of natural gas are recognized when either the service is provided or the product is delivered. Revenues related to these services provided or products delivered but not yet billed are estimated each month.

Gas Sales and Cost of Gas

Gas sales revenue is recorded on the basis of regular meter readings and estimates of customer volume 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 amounts approved by the OEB in the determination of customer sales rates. Differences between the OEB approved reference amounts and those costs actually incurred are deferred in either accounts receivable or accounts payable and accrued charges 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 used 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.

As part of the Company's OEB-approved incentive regulation framework, an earnings sharing mechanism exists whereby earnings above an allowable return on equity are shared with ratepayers. A provision of $4 million was recognized as a reduction of gas sales and distribution revenue and as an obligation in accounts payable and accrued charges for 2010 (2009 – $4 million). Also in 2009, the Company recorded an $11 million charge as a result of a settlement agreement reached with Union Gas' stakeholders with regard to our 2008 utility earnings.

Cash and Cash Equivalents

Cash and cash equivalents consist of cash and short-term investments, with an original maturity of three months or less.

Income Taxes

The asset and liability method of tax allocation is used in the accounting for income taxes for Under this method, future income tax assets and liabilities are recognized for differences between the financial reporting and tax basis of assets and liabilities at enacted, or the substantively enacted, tax rates in effect for the years in which the differences are expected to reverse.

Inventories

Gas in storage for resale to customers is carried at costs approved by the OEB in the determination of customer sales rates. The difference between the approved cost and the actual cost of the gas purchased is deferred in either accounts receivable or accounts payable and accrued charges for future disposition subject to approval by the OEB. Inventories of materials and supplies are valued at the lower of 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.

Regulated depreciation is provided on the straight-line method at various rates based on the average service life of each class of property. Unregulated depreciation rates are based on useful life.

Regulated depreciation rates are determined by periodic review. The depreciation rates for regulated property, plant and equipment are approved by the OEB. Unregulated depreciation rates are determined by management.

When Union Gas retires regulated property, plant and equipment, the Company charges the original cost plus the cost of retirement, less salvage value, to accumulated depreciation and amortization. When the Company sells entire regulated operating units, or retire non-regulated properties, the cost is removed from the property account and the related accumulated depreciation and amortization accounts are reduced. Any gain or loss is recorded in earnings, unless otherwise required 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.

Stock-Based Compensation

Our employees participate in a stock-based compensation plan sponsored by Spectra Energy Corp (Spectra Energy). For employee awards, equity classified stock-based compensation cost is measured at the grant date based on the fair value of the award and is recognized as expense over the requisite service period, which generally begins on the date the award is granted through the earlier of the date the award vests or the date the employee becomes retirement eligible. Awards, including stock options, granted to employees that are already retirement eligible are deemed to have vested immediately upon issuance, and therefore, compensation cost for those awards is recognized on the date such awards are granted.

In addition, certain of our employees that previously participated in our 1989 Long Term Incentive Share Plan have the ability to receive a portion of their converted stock option awards as a stock appreciation right (SAR) paid in cash. Union Gas accounts for these by measuring the amount by which the quoted market price of the underlying stock exceeds the SAR base stock price at the balance sheet date.

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 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 with the market related adjustment determined over a three-year period.

Past service costs from plan amendments are amortized on a straight-line basis over the average remaining service life 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 expected 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 10 and 18 years, respectively.

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

2. Financial Statement Effects of Rate Regulation

The Company records assets and liabilities that result from the regulated ratemaking process that would not be recorded under GAAP for non-regulated entities. See note 1 for further discussion.

($millions)	Financial Statement Location	Recovery/ Settlement Period	**December 31 2010**	December 31 2009
Assets				
Other deferrals – current	a	A	**12**	22
Gas in storage inventory	b	A	**28**	37
Other deferrals – long-term	c	B	**3**	4
Future income taxes – long-term	c	B/C	**214**	174
Total assets			**257**	237
Liabilities				
Other deferrals – current	d	A	**31**	37
Gas cost deferrals	d	A	**39**	186
Storage and transportation deferrals	d	A	**9**	20
Asset removal costs	e	C	**409**	398
Total liabilities			**488**	641

In the absence of rate regulation, the Company's future income tax asset (current) would have been $20 million lower in 2010 (2009 - $68 million lower), and the future income tax liability (long-term) would have been $48 million higher in 2010 (2009 - $58 million higher) as a result of the elimination of the above regulatory assets and liabilities.

Financial Statement Classification

(a) Accounts receivable
(b) Inventories
(c) Regulatory and other assets
(d) Accounts payable and accrued charges
(e) Regulatory and other liabilities

Recovery/Settlement Period

(A) Remaining recovery / settlement is less than 1 year
(B) Remaining recovery / settlement is from 2 to 10 years
(C) Remaining recovery / settlement is over the remaining life of the associated assets

Other deferrals – current

As prescribed by regulatory order, the Company has various amounts included in customer rates that are intended to recover specifically-identified costs. To the extent that the actual costs differ from forecast costs or revenues, the variance is deferred for future recovery from or refund to ratepayers. In the absence of rate regulation, after-tax earnings for 2010 could have been $3 million higher (2009 - $8 million higher) because GAAP for non-regulated entities would require that all customer rate revenue and costs be recognized in income when earned.

Gas in storage

Gas in storage is carried at the weighted average cost of gas as approved by the OEB. In the absence of rate regulation, after-tax earnings for 2010 could have been $9 million higher (2009 - $3 million higher), because GAAP for non-regulated entities would require that gas in storage be recorded at the lower of cost and net realizable value.

Future income taxes

The accounting standard related to income taxes has been amended to require rate-regulated enterprises to recognize future income tax assets and liabilities, and an associated regulatory asset or liability, if applicable, for the amount of future income taxes expected to be recovered from or refunded to ratepayers, and to present these amounts on a gross basis in the financial statements. In the absence of rate regulation, after-tax earnings for 2010 could have been $39 million lower (2009 - $29 million higher) because GAAP for non-regulated entities would require that these amounts be recognized in earnings in the current period.

Gas cost deferrals

The Company and the OEB have a mechanism in place to change gas commodity rates on a quarterly basis, to ensure that customers' rates reflect future expected costs 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. These deferred amounts are subject to review and approval by the OEB on an annual basis in the normal course. 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, after-tax earnings for the 2010 could have been $101 million lower (2009 - $115 million higher), because GAAP for non-regulated entities would require that actual commodity costs be recognized as an expense when incurred.

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 Gas' 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. After-tax earnings for 2010 could have been $8 million lower (2009 - $9 million lower), if these transactions were accounted for under GAAP for non-regulated entities.

Asset removal costs

The Company has recorded a regulatory liability, included in deferred credits and other liabilities, as a result of estimated removal costs for property that does not have an associated legal retirement obligation. In the absence of rate regulation, these costs may not have been recorded and after-tax earnings for 2010 could have been $8 million higher (2009 - $3 million lower).

Property, plant and equipment

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

3. 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 done with gas volumes, changes in the balances do not have an impact on the Company's cash flow from operating activities.

At December 31, 2010 accounts receivable and accounts payable include approximately $194 million (2009 – $102 million) related to gas imbalances and gas balancing services.

4. Inventories

($millions)	**December 31 2010**	December 31 2009
Gas in storage	**157**	208
Materials and supplies	**17**	16
	174	224

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

5. Property, Plant and Equipment, net

($millions)	**December 31 2010**	December 31 2009
Cost		
Distribution	**3,594**	3,483
Transmission	**1,639**	1,596
Storage	**870**	845
General	**267**	263
	6,370	6,187
Accumulated depreciation		
Distribution	**1,086**	1,028
Transmission	**498**	460
Storage	**277**	267
General	**133**	129
	1,994	1,884
Net book value	**4,376**	4,303

The depreciation range of each class of property is as follows:

Distribution	27-60 years
Transmission	30-50 years
Storage	5-50 years
General	4-38 years

Depreciation rates used during the year ended December 31, 2010 resulted in a composite rate of 3.26% (2009 – 3.32%).

Included in property, plant and equipment are the following:

($millions)	**December 31 2010**	December 31 2009
Assets not subject to depreciation[12]	**161**	128
Asset retirement cost	**35**	32
Interest charge capitalized during the year	**1**	4

[12] Assets not subject to depreciation include land, base pressure gas in storage reservoirs and assets under construction.

6. Debt and Credit Facility

Long-term Debt

($millions)		**December 31 2010**	December 31 2009
Sinking fund debentures			
11.55%	1988 Series II debentures, redeemed October 2010	**–**	37
Medium-term note debentures			
7.20%	Series 2, redeemed June 2010	**–**	185
6.65%	Series 3, due May 4, 2011	**250**	250
4.64%	Series 5, due June 30, 2016	**200**	200
5.35%	Series 6, due April 27, 2018	**200**	200
4.85%	Series 7, due April 25, 2022	**125**	125
5.46%	Series 6, due September 11, 2036	**165**	165
6.05%	Series 7, due September 2, 2038	**300**	300
5.20%	Series 8, due July 23, 2040	**250**	–
Other debentures			
7.90%	1994 Series debentures, due February 24, 2014	**150**	150
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
8.65%	Senior debentures, due October 19, 2018	**75**	75
8.65%	1995 Series debentures, due November 10, 2025	**125**	125
		2,240	2,212
Less: deferred financing charges		**12**	11
		2,228	2,201
Less: current portion		**250**	222
		1,978	1,979

The Company’s long-term debt is unsecured. The weighted average cost of long-term debt as at December 31, 2010 was 6.8% (2009 – 7.1%). Principal repayment requirements on long-term debt are as follows:

($millions)	Total	2011	2012	2013	2014	2015	Thereafter
Long-term debt	2,240	250	–	–	150	150	1,690

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, 2010 and 2009, the Company is in compliance with all such covenants.

Total interest paid on long-term debt in 2010 was $150 million (2009 – $160 million).

Available Credit Facility and Restrictive Debt Covenants

	Expiration Date	**Credit Facility Capacity**	**Outstanding at December 31, 2010 Commercial Paper**
Multi-year syndicated[13]	2012	500	157

[13] Credit facility contains a covenant requiring the debt-to-total capitalization ratio to not exceed 75% and a provision which requires Union Gas to repay all borrowings under the facility for a period of two days during the second quarter of each year.

The issuance of commercial paper and other facility borrowings reduces the amount available under the credit facility.

The Company's credit agreement contains various financial and other covenants, including the maintenance of certain financial ratios. Failure to meet those covenants beyond applicable grace periods could result in accelerated due dates and/or termination of the agreement. As of December 31, 2010, the Company was in compliance with those covenants. In addition, the credit agreement allows for the acceleration of payments or termination of the agreement due to non-payment, or in some cases, due to the acceleration of other significant indebtedness of the borrower or some of its subsidiaries.

A majority of the Company's short-term cash requirements are funded through the issuance of commercial paper. The weighted average rate on outstanding commercial paper as of December 31, 2010 was 1.05% (2009 – 0.4%).

Total interest paid on short-term debt in 2010 was $2 million (2009 – $4 million).

7. Mandatorily Redeemable Preference Shares

Authorized		Outstanding at December 31 2010	2009	December 31 2010	December 31 2009
(shares)		*(shares)*		*($millions)*	
Class A – 112,072	Series A, 5.5%	**47,672**	47,672	**3**	3
	Series C, 5.0%	**49,500**	49,500	**2**	2
				5	5

The Class A, Series A and C Preference Shares 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.

8. Share Capital

	Authorized	Outstanding at December 31 2010	2009	December 31 2010	December 31 2009
	(shares)	*(shares)*		*($millions)*	
Class A, Series B, 6%	90,000	**90,000**	90,000	**5**	5
Class B, Series 10, 4.88%	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, Series B Preference Shares are cumulative and redeemable at $55 per share at the option of the Company.

The Class B, Series 10 Preference Shares are cumulative and redeemable at $25 per share at the option of the Company and, at the option of the holders, convertible back into Series 11 shares every five years commencing January 1, 2014. Union Gas may redeem at any time all, but not less than all, of the outstanding Series 10 Shares. The dividend rate of the Series 10 Shares is floating at an annual rate equal to 80% of the prime rate until December 31, 2013.

9. Asset Retirement Obligation

The Company has a legal obligation to disconnect, purge and cap abandoned pipeline, as well as capping abandoned storage wells. 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.

The Company has non-asbestos AROs which include 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 these 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, 2010, the estimated undiscounted cash flows required to settle our AROs was $587 million (2009 – $573 million), calculated using an inflation rate of 2.0% per annum (2009 – 2.0%). The estimated fair value of this liability was $123 million (2009 – $108 million). The estimated cash flows of new obligations incurred during the year have been discounted at a rate of 3.80% per annum (2009 – 4.22%). At December 31, 2010, the timing of payment for settlement of the obligations ranges from 1 to 147 years.

Reconciliation of Asset Retirement Obligations:

($millions)	**December 31 2010**	December 31 2009
Balance, beginning of year	**108**	75
Liabilities incurred	**10**	32
Liabilities settled	**(1)**	(3)
Accretion	**6**	4
Balance, end of year	**123**	108

10. 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 Gas. 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. 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.

The Spectra Energy 2007 Long-Term Incentive Plan (the 2007 LTIP) provides for the granting of stock options, restricted stock awards and units, unrestricted stock awards and units, and other equity-based awards, to employees and other key individuals who perform services for Spectra Energy. A maximum of 30 million shares of common stock may be awarded under the 2007 LTIP. Union Gas employees participate in the 2007 LTIP. Options granted under the 2007 LTIP are issued with exercise prices equal to the fair market value of the Spectra Energy common stock on the grant date, have ten year terms and vest immediately or over terms not to exceed three years. Compensation expense related to stock options is recognized over the requisite service period. The requisite service period for stock options is the same as the vesting period, with the exception of retirement eligible employees, who have shorter requisite service periods ending when the employees become retirement eligible.

Restricted, performance and phantom stock awards granted under the 2007 LTIP typically become 100% vested on the three-year anniversary of the grant date. The fair value of the awards granted is measured based on the fair value of the shares on the date of grant. Related compensation expense is recognized over the requisite service period which is the same as the vesting period.

At the time of the Spectra Energy spin-off from Duke Energy, Duke Energy converted stock options, restricted stock awards, performance awards and phantom stock awards (collectively, Stock-Based Awards) of Duke Energy common stock held by Spectra Energy employees and Duke Energy employees. One replacement Duke Energy Stock-Based Award and one-half Spectra Energy Stock-Based Award were distributed to each holder of Duke Energy Stock-Based Awards for each award held at the time of the spin-off. The Spectra Energy Stock-Based Awards resulting from the conversion are considered to have been issued under the 2007 LTIP.

Spectra Energy allocated pre-tax stock-based compensation expense included in continuing operations to Union Gas for 2010 and 2009 as follows, the components of which are further described below:

($millions)	**December 31 2010**	December 31 2009
Phantom Stock	**1**	1
Performance Awards	**1**	1
Total	**2**	2

Stock Options

	Shares	**Weighted-Average Exercise Price US$**
Outstanding at beginning of year	**251,975**	**$25**
Transfers in/(out)	**(22,474)**	**24**
Granted	**–**	
Exercised	**(9,062)**	**18**
Forfeited	**(18,681)**	**31**
Outstanding at end of year	**201,758**	**$25**
Options exercisable at year-end	**201,758**	**$25**

	Options Outstanding			**Options Exercisable**	
Exercise Prices US$	Number Outstanding At 12/31/10	Weighted-Average Remaining Contractual Life(in years)	Weighted-Average Exercise Price US$	Number Exercisable At 12/31/10	Weighted-Average Exercise Price US$
$11 – 15	21,050	2.2	$12	21,050	$12
$16 – 20	–	–	–	–	–
$21 – 25	146,657	5.9	26	146,657	26
$26 – 30	12,351	1.1	29	12,351	29
$31 – 37	21,700	1.1	33	21,700	33
> $37	–	–	–	–	–
Total	201,758	4.7	$25	201,758	$25

The Company did not award non-qualified stock options to employees during 2010 or 2009. Under the terms of the 2007 LTIP, the exercise price of a non-qualified stock option shall not be less than 100% of the fair market value of Spectra Energy common stock on the date of grant, and the maximum option term is ten years. Spectra Energy issues new shares upon exercising or vesting of share-based awards. The Black-Scholes option-pricing model is used to estimate the fair value of options at grant date. The risk-free rate of return is determined based on a yield curve of U.S. Treasury rates ranging from six months to ten years and a period commensurate with the expected life of the options granted. The expected volatility is established based on historical volatility and implied volatility of a group of 19 peer company stock prices. The expected dividend yield is determined based on Spectra Energy's annual dividend amount as a percentage of the average stock price at the time of grant.

Performance Awards

Under the 2007 LTIP, the Company can also grant performance awards. Stock-based performance awards generally vest over three years at the earliest, if performance metrics are met. The Company granted 59,400 performance awards (fair value of US $2 million) during 2010 and 67,600 performance awards (fair value of US $1 million) during 2009.

The unvested and outstanding performance awards granted contain market conditions based on the total shareholder return (TSR) of Spectra Energy common stock relative to a pre-defined peer group. These awards are valued using the Monte Carlo valuation method.

Weighted-Average Assumptions for Market Based Awards

	December 31 2010	December 31 2009
Risk free interest rate	**1.4%**	**1.4%**
Expected life (years)	**3**	**3**
Expected volatility Spectra Energy	**37.9%**	**41.2%**
Expected volatility Peer Group	**22.3-58.5%**	**20.8-53.1%**
Market Index	**30.3%**	**28.5%**
Expected dividend yield	**–**	**–**

The risk-free rate of return was determined based on a yield of three year U.S. Treasury bonds on the grant date. The expected volatility was established based on historical volatility over three years using daily stock price observations. A shorter period was used if three years of data was not available. Because the award payout includes dividend equivalents, no dividend yield assumption is required.

The total fair value of the performance shares vested was $333,746 in 2009, $333,522 in 2008. No performance shares vested in 2010. As of December 31, 2010, the Company expects to recognize $2 million of future compensation cost related to stock awards over a weighted-average period of less than two years.

Phantom Stock Awards

Stock-based phantom awards granted under the 2007 LTIP generally vest over three years. The Company awarded 65,600 phantom awards (fair value $1 million) during 2010, and 47,600 phantom awards (fair value of $1 million) during 2009.

The total fair value of the phantom shares vested was $778,935 in 2010 and $111,258 in 2009.

11. Capital Management

The Company's objectives in managing its capital include the continuation of its ability to serve customers and to generate the OEB allowed rate of return for its shareholders while maintaining the OEB-approved level of common equity.

In managing capital, management considers both debt and equity. The mix of debt and equity components is driven by prevailing market conditions, as the Company may take advantage of lower interest rates by issuing debt or utilizing available credit facilities. The Company is required by Undertakings to the Lieutenant Governor in Council of Ontario to maintain sufficient common equity at the level approved by the OEB. The quarterly dividend payment is determined to allow the Company to maintain the common equity component at the level approved by the OEB.

Various debt covenants require the Company's Indebtedness[14] not to exceed 75% of Total Capitalization[15].

As at December 31, 2010 and 2009, the Company was in compliance with the following externally imposed capital requirements. The Company monitors these requirements on a quarterly basis.

	December 31 2010	December 31 2009
OEB-approved minimum Common Equity	**36.00%**	36.00%
Allowed Return on Equity – regulated operations	**8.54%**	8.54%
Maximum Total Indebtedness to Total Capitalization	**75.00%**	75.00%
Actual Total Indebtedness to Total Capitalization	**64.10%**	61.00%

12. Financial Instruments

Under Canadian GAAP, financial instruments are classified into one of the following five categories: held-for trading, held to maturity investments, loans and receivables, available-for-sale financial assets and other financial liabilities. The carrying value of the Company's financial instruments are classified into the following categories:

Classification *($millions)*	**December 31 2010**	December 31 2009
Financial assets held for trading[16]	**12**	34
Loans and receivables[17]	**301**	269
Other financial liabilities[18]	**2,793**	2,471

The fair values of the Company's financial instruments are not materially different from their carrying value, with the exception of the Company's long-term debt of $2,240 million (2009 – $2,212 million). Based on current interest rates for debt with similar terms and maturities, the fair market value is estimated to be $2,610 million (2009 – $2,484 million).

[14] Indebtedness includes short-term borrowings, commercial paper, long-term debt, mandatorily redeemable preference shares and letters of credit.
[15] Capitalization includes shareholders-equity, non-controlling interest and indebtedness.
[16] Includes cash and cash equivalents
[17] Includes accounts receivable
[18] Includes accounts payable and accrued charges, short-term borrowings, long-term debt, and mandatorily redeemable preference shares

Fair value hierarchy

Financial instruments recorded at fair value on the Consolidated Balance Sheet are valued using a fair value hierarchy that reflects the significance of the inputs used in making the measurements. The fair value hierarchy has the following levels:

Level 1 - valuation based on quoted prices (unadjusted) in active markets for identical assets or liabilities;

Level 2 - valuation techniques based on inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly (i.e. as prices) or indirectly (i.e. derived from prices);

Level 3 - valuation techniques using inputs for the asset or liability that are not based on observable market data (unobservable inputs).

The fair value hierarchy requires the use of observable market inputs whenever such inputs exist. A financial instrument is classified to the lowest level of the hierarchy for which a significant input has been considered in measuring fair value.

Cash and cash equivalents are the only financial instruments recorded at fair value on the Consolidated Balance Sheet and are classified as level 1.

Interest rate risk

Interest rate risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market interest rates. The long-term debt bears interest at fixed rates and therefore the cash flow exposure is not significant. However, the fair value of loans having fixed rates of interest could fluctuate because of changes in market interest rates. The fair value of short-term borrowings have a limited exposure to interest rate risk due to their short-term maturity.

Credit risk

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligation. The maximum exposure to credit risk of the Company at period end is the carrying value of its financial assets. The Company’s principal customers for natural gas transportation and storage services are industrial end-users, marketers, local distribution companies and utilities. The Company’s distribution customers are primarily industrial and residential end-users. These concentrations of customers may affect the Company’s overall credit risk.

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, 2010 is $72 million receivable (2009 - $39 million receivable). 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.

The Company manages its credit risk on cash and cash equivalents by dealing solely with reputable banks and financial institutions. To manage its credit risk on accounts receivable, the Company performs ongoing credit reviews of all its customers. In cases where the credit quality of a customer does not meet the Company’s requirements, a cash deposit, letter of credit or parental guarantee is required. Deposits held by the Company at December 31, 2010 amounted to $51 million (2009 - $58 million). Significant financial difficulties of the debtor, the probability that the debtor will enter bankruptcy or financial reorganization, and default or delinquency in payments are considered indicators that the account receivable may be uncollectible and therefore should be included in the allowance for doubtful accounts.

Union Gas continues to utilize its established risk management policies and procedures to ensure the appropriate monitoring of customer credit positions and, based on current evaluations, does not expect any significant negative impacts associated with these positions.

The following table sets forth details of the age of trade receivables that are not impaired as well as the allowance for the doubtful accounts:

($millions)	**December 31 2010**	December 31 2009
Current	**282**	242
30 Days over due	**9**	9
60 Days over due	**3**	3
90+ Days over due	**6**	10
Total trade accounts receivable	**300**	264
Allowance for doubtful accounts	**(5)**	(6)
Total trade accounts receivable, net[19]	**295**	258

For the years ended December 31, 2010 and 2009, no one customer accounted for more than 10% of sales or 10% of receivables.

Equity Price Risk

Our costs of providing non-contributory defined benefit retirement and postretirement benefit plans are dependent upon, among other things, rates of return on plan assets. These plan assets expose us to price fluctuations in equity markets. In addition, our captive insurance company maintains various investments to fund certain business risks and losses. Those investments may, from time to time, include investments in equity securities. Currently, we do not invest in equity securities other than employee benefits plan assets.

Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its obligations as they become due. The Company manages its liquidity risk by forecasting cash flows from operations and anticipated investing and financing activities. The Company has credit facilities available to help meet short-term financing needs (note 6).

The following are the contractual maturities of the undiscounted cash flows of financial liabilities as at December 31, 2010:

($millions)	Total	Less than 1 year	2 – 3 years	4 – 5 years	More than 5 years
Short-term borrowings	198	198	–	–	–
Commercial paper	157	157	–	–	–
Accounts payable and accrued charges	582	582	–	–	–
Long-term debt (including principal and interest)	4,123	402	271	560	2,890
Mandatorily redeemable preference shares	5	–	–	–	5
Total	5,065	1,339	271	560	2,895

[19] The carrying amount of accounts receivable is impacted by changes in gas prices, which may fluctuate significantly from year to year.

13. 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. Our eligible employees 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. Other post-retirement benefits provided include health and dental benefits, life insurance coverage and a health care spending account.

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 associated with the change in accounting for Employee Future Benefits 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 EARSL of employees active at the date of the amendment. The amount by which the net unamortized cumulative actuarial gain or loss based on the market related value of assets 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. The average remaining service period of the active employees eligible for post retirement benefits other than pensions is 18 years.

The Company made the following employee future benefit contributions:

($millions)	**December 31 2010**	December 31 2009
Defined benefit plans	**40**	41
Defined contribution pension plan	**5**	4
Supplemental pension	**1**	1
Other than pensions	**2**	3
	48	49

Actuarial Valuations

	Pension Benefit Plans	**Post-Retirement Benefits Other Than Pensions**
Most recent	January 1, 2010	January 1, 2009
Next scheduled	January 1, 2011	January 1, 2012

Benefit Obligations, Plan Assets and Funded Status

	Years Ended December 31			
	Pension		Other	
($millions)	**2010**	2009	**2010**	2009
Change in benefit obligations				
Balance, beginning of year	**585**	529	**60**	49
Employer current service cost	**11**	9	**2**	1
Member contributions	**3**	3	**–**	–
Interest cost	**34**	31	**3**	3
Benefits paid	**(30)**	(27)	**(2)**	(3)
Past service cost	**7**	–	**–**	–
Actuarial loss	**45**	40	**6**	10
Balance, end of year	**655**	585	**69**	60
Change in fair value of assets				
Fair value, beginning of year	**443**	418	**–**	–
Actual return on plan assets	**45**	6	**–**	–
Employer contributions	**42**	43	**2**	3
Member contributions	**3**	3	**–**	–
Benefits paid	**(30)**	(27)	**(2)**	(3)
Fair value, end of year	**503**	443	**–**	–
Funded status				
Net funded status	**(152)**	(142)	**(69)**	(60)
Unamortized net actuarial loss	**258**	238	**17**	11
Unamortized past service costs	**12**	7	**–**	–
Unamortized transitional obligation	**6**	7	**8**	9
Contributions remitted after measurement date	**10**	11	**–**	1
Accrued benefit asset (liability), end of year	**134**	121	**(44)**	(39)
Classification of accrued benefit assets (liabilities)				
Regulatory and other assets	**152**	137	**–**	–
Regulatory and other liabilities	**(18)**	(16)	**(44)**	(39)
Accrued benefit asset (liability)	**134**	121	**(44)**	(39)
Allocation of assets to major classes				
Equity securities	**54%**	60%	**–**	–
Debt securities	**46%**	40%	**–**	–

For 2010 and 2009, all of the defined benefit pension plans had accrued benefit obligations that exceeded the fair value of plan assets. The other post-retirement benefit plans are not pre-funded.

Net benefit cost

	Years Ended December 31,			
	Pension		**Other**	
($millions)	**2010**	2009	**2010**	2009
Current service cost	**11**	9	**2**	1
Interest cost	**34**	31	**3**	3
Actual return on plan assets	**(45)**	(6)	**–**	–
Actuarial losses	**45**	40	**6**	10
Past service cost	**7**	–	**–**	–
Elements of employee future benefits costs before adjustments to recognize the long-term nature of employee future benefit costs	**52**	74	**11**	14
Adjustments to recognize the long-term nature of employee future benefit costs:				
Difference between actual and expected return	**11**	(27)	**–**	–
Difference between actual and recognized actuarial gains in year	**(31)**	(34)	**(6)**	(10)
Difference between actual and recognized past service costs in year	**(5)**	1	**–**	–
Amortization of transitional obligation	**1**	2	**2**	2
Defined benefit costs recognized	**28**	16	**7**	6
Defined contribution cost	**5**	4	**–**	–
Total net benefit cost	**33**	20	**7**	6

Weighted average assumptions used to determine benefit liability

	Years Ended December 31,			
	Pension		**Other**	
	2010	2009	**2010**	2009
Discount rate at measurement date	**5.04%**	5.62%	**5.11%**	5.69%
Rate of compensation increase	**3.25%**	3.50%	**3.25%**	3.50%
Initial overall health care trend rate	**–**	–	**8.00%**	8.00%
Annual rate of decline in health care trend rate	**–**	–	**0.50%**	0.50%
Ultimate health care cost trend rate	**–**	–	**5.00%**	5.00%
Year that the rate reaches the ultimate trend rate	**–**	–	**2017**	2016

Weighted average assumptions used to determine net benefit cost

	Years Ended December 31,			
	Pension		**Other**	
	2010	2009	**2010**	2009
Discount rate	**5.62%**	5.98%	**5.69%**	6.03%
Expected rate of return on plan assets	**7.00%**	7.00%	**–**	–
Rate of compensation increases	**3.50%**	3.50%	**3.50%**	3.50%
Initial overall health care trend rate	**–**	–	**8.00%**	8.00%
Annual rate of decline in health care trend rate	**–**	–	**0.50%**	0.50%
Ultimate health care cost trend rate	**–**	–	**5.00%**	5.00%
Year that the rate reaches the ultimate trend rate	**–**	–	**2016**	2015

Sensitivity of key assumption

($millions)	**Post-Retirement Benefits Other than Pensions**	
Assumed change in health care cost trend rate	**1% Increase**	**1% Decrease**
Change in obligation	**6**	(6)

14. Income Taxes

The provision for income taxes consists of the following:

($millions)	**December 31 2010**	December 31 2009
Current	**16**	103
Future	**25**	(55)
	41	48

The year-over-year change in the components of current and future 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 2010 were $96 million (2009 - $47 million).

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

($millions)	**December 31 2010**	December 31 2009
Income before income taxes	**247**	223
Statutory income tax rate (percent)	**31.0**	33.0
Statutory income tax rate applied to accounting income	**77**	74
Increase/(decrease) resulting from:		
Future tax recovery resulting from tax rate changes	**(4)**	(44)
Future regulatory income tax payable/receivable recorded through tax expense	**(32)**	18
Provision for income taxes	**41**	48
Effective rate of income tax (percent)	**16.6**	21.0

The future income taxes recorded in current assets of $14 million (2009 – $57 million) arise from temporary differences primarily related to regulatory deferral accounts.

The long-term future income tax liability of $361 million (2009 - $327 million) includes the following:

($millions)	**December 31 2010**	December 31 2009
Temporary differences related to pension asset	**26**	26
Temporary differences related to accelerated depreciation rates	**335**	301
	361	327

15. Related Party Transactions

The Company purchases gas, storage and transportation services at prevailing market prices and under normal trade terms from related parties. During the year ended December 31, 2010, these purchases totalled $11 million (2009 – $6 million). Union Gas also provides storage and transportation services to related parties which totalled $1 million during 2010 (2009 – $1 million).

The Company provided administrative, management and other services to related parties totalling $10 million (2009 – $9 million), which were billed and recovered at cost. Charges from related parties for administrative and other goods and services were $9 million (2009 – $7 million).

At December 31, 2010 the Company had receivable balances of $2 million (2009 – $6 million) and payable balances of $3 million (2009 – $6 million) with related parties, all of which are recorded in accounts receivable and accounts payable, respectively.

During 2010, the Company obtained from and provided unsecured loans to Westcoast. The balance outstanding on these loans at December 31, 2010 was a $198 million payable (2009 – $6 million receivable). These loans are classified as short-term borrowings in 2010. Interest received on these loans during 2010 totalled less than $1 million (2009 – less than $1 million) and interest paid on these loans totalled less than $1 million (2009 – less than $1 million). Interest on these loans is calculated based on the monthly average of 30-day banker's acceptance rates.

16. 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 could have a significant impact on its consolidated financial statements.

DIRECTORS

David G. Unruh

Julie A. Dill

Bruce E. Pydee

OFFICERS

Julie A. Dill
Chair and President

J. Patrick Reddy
Chief Financial Officer

M. Richard Birmingham
Vice President, Regulatory, Government, Aboriginal and Public Affairs

Bruce E. Pydee
Vice President and General Counsel

Bohdan I. Bodnar
Vice President, Human Resources

Menelaos Ydreos
Vice President, Marketing and Customer Care

Allen C. Capps
Vice President, Business Development – Storage and Transmission

Paul Rietdyk
Vice President, Distribution Operations

Michael P. Shannon
Vice President, Engineering, Construction and Storage and Transmission Operations

Joe R. Martucci
Vice President, Finance

Stephen W. Baker
Vice President and Treasurer

Timothy Kennedy
Vice President, Federal Government Affairs

Paul K. Haralson
Assistant Treasurer

Patricia M. Rice
Corporate Secretary

Leigh A. Hodgins
Assistant Secretary

Joseph Marra
Assistant Secretary

CORPORATE INFORMATION

Transfer Agent and Registrar **CIBC Mellon**

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

Class A Preference, Series B – 6% (UNG.PR.D)

REGISTERED OFFICE

50 Keil Drive North Chatham, Ontario N7M 5M1

Filed: 2011-11-10
EB-2011-0210
Exhibit A3
Tab 2

SECOND QUARTER INTERIM REPORT, JUNE 30, 2011

Q2

uniongas
A Spectra Energy Company
CELEBRATING
100 YEARS
Est. 1911

August 5, 2011

This discussion and analysis of Union Gas Limited for the six months ended June 30, 2011, should be read in conjunction with the interim unaudited consolidated financial statements and accompanying notes. The terms ("we," "our", "us" and "Union Gas") as used in this report refer collectively to Union Gas Limited and its subsidiary unless the context suggests otherwise. These terms are used for convenience only and are not intended as a precise description of any separate legal entity within Union Gas. 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 us, including our most recent Annual Report for the fiscal year ended December 31, 2010 and our most recent Annual Information Form can be found at www.sedar.com.

FORWARD LOOKING INFORMATION

This Management's Discussion and Analysis (MD&A) includes forward-looking statements. Forward-looking statements are based on management's beliefs and assumptions. These forward-looking statements are identified by terms and phrases such as: anticipate, believe, intend, estimate, expect, continue, should, could, may, plan, project, predict, will, potential, forecast, and similar expressions. Forward-looking statements involve risks and uncertainties that may cause actual results to be materially different from the results predicted. Factors that could cause actual results to differ materially from those indicated in any forward-looking statement include, but are not limited to:

- local, provincial and federal legislative and regulatory initiatives that affect cost and investment recovery, have an effect on rate structure, and affect the speed at and degree to which competition enters the natural gas industries;
- outcomes of litigation and regulatory investigations, proceedings or inquiries;
- weather and other natural phenomena, including the economic, operational and other effects of storms;
- the timing and extent of changes in commodity prices and interest rates;
- general economic conditions which can affect the long-term demand for natural gas and related services;
- potential effects arising from terrorist attacks and any consequential or other hostilities;
- changes in environmental, safety and other laws and regulations;
- the development of alternative energy resources;
- results of financing efforts, including the ability to obtain financing on favourable terms, which can be affected by various factors, including credit ratings and general economic conditions;
- increases in the cost of goods and services required to complete capital projects;
- declines in the market prices of equity and debt securities and resulting funding requirements for defined benefit pension plans;
- growth in opportunities, including the timing and success of efforts to develop pipeline, storage, and other infrastructure projects and the effects of competition;
- the performance of transmission, storage and distribution facilities;
- the extent of success in connecting natural gas supplies to transmission systems and in connecting to expanding gas markets;
- the effects of accounting pronouncements issued periodically by accounting standard-setting bodies;

- conditions of the capital markets during the periods covered by the forward-looking statements; and
- the ability to successfully complete merger, acquisition or divestiture plans; regulatory or other limitations imposed as a result of a merger, acquisition or divestiture; and the success of the business following a merger, acquisition or divestiture.

In light of these risks, uncertainties and assumptions, the events described in the forward-looking statements might not occur or might occur to a different extent or at a different time than we have described. We undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise, except as required by law.

GENERAL

Union Gas is a major Canadian natural gas storage, transmission and distribution company based in Ontario with 100 years of experience and service to customers. The distribution business serves over 1.3 million residential, commercial and industrial customers in more than 400 communities across northern, southwestern and eastern Ontario. Union Gas' growing storage and transmission business offers premium storage and transportation services to customers at the Dawn Hub (Dawn). Dawn is the largest underground storage facility in Canada and one of the largest in North America. It offers customers an important link in the movement of natural gas from Western Canadian and U.S. supply basins to markets in central Canada and the northeast U.S.

HIGHLIGHTS

($millions except where noted)	Three Months Ended June 30 2011	2010	Six Months Ended June 30 2011	2010
Income				
Total operating revenues	**361**	340	**1,048**	1,035
Net income applicable to common shares	**35**	28	**131**	112
Dividends				
Dividends on preference shares	–	–	**1**	1
Dividends on common shares	**16**	16	**32**	32
Assets and long-term liabilities				
Total assets	**5,462**	5,315	**5,462**	5,315
Total long-term liabilities	**3,263**	2,648	**3,263**	2,648
Volumes of gas (10^6m^3)[1]				
Distribution volumes	**2,765**	2,490	**7,963**	6,966
Transportation volumes	**4,371**	5,074	**13,623**	13,578
Total throughput	**7,136**	7,564	**21,586**	20,544
Customers *(thousands)*	**1,348**	1,331	**1,348**	1,331
Heating degree days[2] *(degree Celsius)*				
Actual	**517**	379	**2,612**	2,224
Normal[3]	**522**	521	**2,507**	2,493

[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 average temperature falls below 18 degrees Celsius. A temperature of zero degrees Celsius equals 18 heating degree days.
[3] As per Ontario Energy Board approved methodology used in setting rates.

RESULTS OF OPERATIONS

	For the Three Month Period Ended June 30			For The Six Month Period Ended June 30		
($millions)	2011	2010	**Increase (Decrease)**	2011	2010	**Increase (Decrease)**
Gas sales and distribution revenue	276	258	**18**	875	866	**9**
Cost of gas	122	113	**9**	487	500	**(13)**
Gas distribution margin	154	145	**9**	388	366	**22**
Storage and transportation revenue	78	74	**4**	161	155	**6**
Other revenue	7	8	**(1)**	12	14	**(2)**
	239	227	**12**	561	535	**26**
Expenses	157	153	**4**	316	311	**5**
Interest expense	36	39	**(3)**	74	78	**(4)**
Income taxes	11	7	**4**	39	33	**6**
Net income	35	28	**7**	132	113	**19**
Preference share dividends	–	–	–	1	1	–
Net income applicable to common shares	35	28	**7**	131	112	**19**

Three month period ended June 30, 2011 compared to three month period ended June 30, 2010

Gas sales and distribution revenue. The $18 million increase was mainly driven by:

- a $48 million increase in customer usage of natural gas due to weather that was more than 36% colder than in the same period in the prior year, partially offset by
- a $29 million decrease from lower natural gas prices[4] passed through to customers without a mark-up.

Cost of gas. The $9 million increase was mainly driven by:

- a $41 million increase due to higher volumes of natural gas sold as a result of weather that was more than 36% colder than in the same period in the prior year, partially offset by
- a $29 million decrease from lower natural gas prices passed through to customers.

Six month period ended June 30, 2011 compared to six month period ended June 30, 2010

Gas sales and distribution revenue. The $9 million increase was mainly driven by:

- a $127 million increase in customer usage of natural gas due to weather that was more than 17% colder than in the same period in the prior year, and
- a $13 million increase from growth in the number of customers, partially offset by
- a $126 million decrease from lower natural gas prices passed through to customers without a markup.

[4] Natural Gas prices passed through to customers without a mark-up are based on the 12 month New York Mercantile Exchange

Cost of gas. The $13 million decrease was mainly driven by:

- a $126 million decrease from lower natural gas prices passed through to customers, partially offset by
- a $107 million increase due to higher volumes of natural gas sold as a result of weather that was more than 17% colder than in the same period in the prior year, and
- a $10 million increase from growth in the number of customers.

QUARTERLY RESULTS

($millions)	Q3 2009	Q4 2009	Q1 2010	Q2 2010	Q3 2010	Q4 2010	Q1 2011	Q2 2011
Gas sales and distribution revenue	184	458	608	258	186	441	599	276
Storage and transportation revenue	73	71	81	74	75	78	83	78
Other revenue	10	11	6	8	9	6	5	7
Total operating revenues	267	540	695	340	270	525	687	361
Net income	11	50	85	28	15	78	97	35
Net income applicable to common shares	10	50	84	28	14	78	96	35

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 weather variations relative to demand during the winter heating season. Changes in natural gas rates that are charged to customers result in corresponding changes in gas sales and distribution revenue. These increases or decreases in gas sales revenue are completely offset in the cost of gas, as a result of the associated regulatory recovery and refund mechanisms.

RATE REGULATION

Union Gas is regulated by the Ontario Energy Board (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. We are subject to regulation with respect to the rates that we may charge our customers, system expansion or facility abandonment, adequacy of service, public safety aspects of pipeline system construction and certain accounting practices.

Non-Commodity Deferral Account Disposition

In April 2011, we applied for the annual disposition of the 2010 non-commodity deferral account balances. The combined impact on customers, including the impact of incentive regulation earnings sharing for 2010, is a refund payable to customers of approximately $6 million. A hearing is expected later this year, with implementation of the refund proposed for the six-month period starting October 1, 2011.

Sale of St. Clair Line

A hearing to address the delay in the disposition of the deferral accounts associated with the proposed sale of the St. Clair Line was held on April 6, 2011. In May 2011, the OEB released its decision finding that the deferral accounts will only be disposed of if the sale of the St. Clair Line is completed, on or before December 31, 2011. If the sale does not take place on or before December 31, 2011, the deferral account balance of $8 million will be taken into income and the St. Clair Line will be returned to regulated rate base.

Jacob Pool

In June 2010, Union Gas purchased a depleted gas reservoir in the Municipality of Chatham-Kent from Torque Energy Inc. and Liberty Oil & Gas Ltd. This reservoir is now referred to as Jacob Pool. In July 2011, the OEB approved Jacob Pool to be designated as a gas storage area and authorized the injection, storage and removal of gas from this area.

Demand Side Management

The OEB has been consulting with stakeholders on the guidelines for the next long-term Demand Side Management (DSM) framework for the natural gas utilities. Guidelines were issued by the OEB on June 30, 2011. These guidelines allow for annual inflationary increases to the DSM budget, and introduce some changes to the program portfolio. Union Gas is preparing to consult with stakeholders later this summer, and must file its 3-year DSM plan for approval by the OEB by September 15, 2011.

LIQUIDITY AND CAPITAL RESOURCES

We manage cash to maximize value while assuring appropriate amounts of cash are available, as required. We invest our available cash in high-quality money market securities. Such money market securities are designed for the safety of principal and for liquidity, and accordingly do not include equity-based securities.

We meet our short-term cash requirements through funds generated from operations, the utilization of loans from Westcoast Energy Inc. and the issuance of commercial paper. Long-term capital requirements for expansion, maintenance and investments are met through the combination of cash flow from operations, issuance of long-term debt and preference shares.

Changes in Cash Flow

	Three Months Ended June 30		Six Months Ended June 30	
($millions)	**2011**	2010	**2011**	2010
Operating activities	**125**	51	**414**	186
Investing activities	**(63)**	(46)	**(114)**	(78)
Financing activities	**(50)**	(5)	**(296)**	(141)

Operating Activities

Union Gas' heating season extends from approximately November through March. We begin the heating season with near-capacity natural gas inventory levels which are drawn throughout the heating season. Inventory levels decrease from December and thus contribute to a positive cash flow from operations during the first quarter. 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.

Some of our customers purchase gas directly from marketers. Marketers typically deliver gas to us evenly throughout the year, whereas most of their customers use gas based on seasonality. As part of our normal billing process, we bill the marketers' customers as gas is used and remit this cash to the marketer when gas is delivered to us. Therefore, during the first and fourth quarters of the year, customers typically use more gas than is delivered to us and we collect cash from the marketers' customers creating a positive cash flow. During the second and third quarters, marketers deliver more gas than their customers use, thus creating a significant cash outflow. These are normal seasonal trends.

The primary factors increasing cash flow from operations for the three months and six months ended June 30, 2011 compared to 2010 include higher refunds to customers in 2010 of over collection of commodity costs in 2009, and a large final payment of 2009 taxes made in 2010, offset by higher customer receivables due to colder weather and lower collections in 2011 due to a lower spread between commodity rates charged to customers and actual gas costs.

Investing Activities

The primary factor decreasing cash flow from investing activities for the three months and six months ended June 30, 2011 compared to 2010 was higher maintenance expenditures.

Financing Activities

In May 2011, we retired, at par, $250 million of Series 3 medium-term note debentures at 6.65% per annum.

In June 2011, we issued $300 million of Series 9 medium-term note debentures at 4.88% per annum, due June 2041. Net proceeds from the offering will be used for general corporate purposes, including refinancing of the May 2011 retirement.

In order to maintain the common equity component of the capital structure at a level no greater than that approved by the OEB, we typically pay a quarterly dividend to our parent company. During each of the first two quarters of 2011 and 2010, we paid a $16 million dividend to our parent. In the first quarter of 2010 we also paid a $116 million additional dividend declared in December 2009.

OUTSTANDING SHARES

	June 30 2011	December 31 2010	June 30 2010
Redeemable Preference Shares			
Class A, Series A, 5.5%	**47,672**	47,672	47,672
Class A, Series C, 5.0%	**49,500**	49,500	49,500
Preference Shares			
Class A, Series B, 6.0%	**90,000**	90,000	90,000
Class B, Series 10, 4.88%	**4,000,000**	4,000,000	4,000,000
Common Shares	**57,822,650**	57,822,650	57,822,650

FINANCIAL CONDITION

Ratings Summary

	Standard & Poor's	**DBRS**
Commercial paper	A – 1 (low)[5]	R – 1 (low)
Debentures	BBB+	A
Preference shares	P – 2 (low)[6]	Pfd – 2

Our credit ratings remain unchanged from those reported in the 2010 Annual Report.

The above credit ratings are dependent upon, among other factors, the ability to generate sufficient cash to fund capital and investment expenditures, our results of operations, market conditions and other factors. Our credit ratings could impact our ability to raise capital in the future, impact the cost of our capital and, as a result, have an impact on our liquidity.

[5] Represents Canadian National Scale Commercial Paper Rating.
[6] Represents Canadian Preferred Stock Rating.

OUTLOOK

Storage and Transportation

As a result of lower gas volumes being transported on TransCanada PipeLines Limited's (TCPL) main line, TCPL is reviewing its toll structure. With the potential for long-haul or short-haul toll increases, customers may find alternative, less expensive, sources of supply. Since our system connects directly with the impacted short-haul paths, this could result in a decline in the use of our storage and transportation system. Also, declining supply into Dawn and constraints in takeaway capacity downstream of the Parkway compressor station site (Parkway), may affect liquidity at Dawn and storage pricing. To address these concerns, Union Gas will continue to focus on adding new flexible services to attract new supply to Dawn. We are also evaluating new infrastructure projects that can more directly connect downstream markets and upstream supply to Dawn without using third party pipelines.

Environmental, Health and Safety

In May 2011, the Workplace Safety and Insurance Board conducted a Workwell audit within Union Gas. This audit occurred as a result of an employee vehicle fatality in late 2009. At the conclusion of the audit, Union Gas was notified that we had successfully passed the audit and that we were one of few multi-site companies in Ontario to have ever passed an audit on the first attempt. This is a recognition that we are not only a compliant organization, but also one that has a very strong safety culture.

RISK FACTORS

In addition to other information set forth in this report, careful consideration should be given to the "Risk Factors" in our Annual Report for the year ended December 31, 2010 which could adversely affect our business and earnings level. Other than the amendments to the risk factor below, there have been no material changes to those risk factors.

Regulatory Risk

Our pipelines are regulated by the Ontario Technical Standards and Safety Authority (TSSA) and the National Energy Board (NEB).

Through our participation on the TSSA Pipeline Risk Reduction Group we have the opportunity to provide input and influence the direction of the regulatory changes. The amendments to the Ontario regulations that the TSSA is proposing will have an impact on our Integrity Management Program and the direction the US industry is taking may prompt some further regulatory requirements.

We have very limited NEB regulated assets, so the minor amendments proposed related to Management Systems will not have a significant impact on our business.

DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROLS OVER FINANCIAL REPORTING

Disclosure Controls and Procedures

Disclosure controls and procedures are controls and other procedures that are designed to: (a) provide reasonable assurance that material information required to be disclosed by us is accumulated and communicated to management to allow timely decisions regarding required disclosure; and (b) ensure that information required to be disclosed by us is recorded, processed, summarized, and reported within the time periods specified in applicable securities legislation.

Internal Control over Financial Reporting

Our management is responsible for designing, establishing and maintaining an adequate system of internal control over financial reporting. Our internal control system was designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes, in accordance with Canadian GAAP. Because of inherent limitations, internal control over financial reporting may not prevent or detect all misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with policies and procedures may deteriorate.

Changes in Internal Control over Financial Reporting

Under the supervision and with the participation of management, including the President and Chief Financial Officer, we have evaluated changes in internal control over financial reporting that occurred during the quarter ended June 30, 2011 and found no change that has materially affected, or is reasonably likely to materially affect, internal control over financial reporting.

Our Board of Directors has reviewed and approved this MD&A and the attached unaudited interim consolidated financial statements prior to their release.

ACCOUNTING CHANGES

New Accounting Pronouncements – 2011

The Canadian Institute of Chartered Accountants (CICA) issued Section 1601, Consolidated Financial Statements and Section 1602, Non-controlling Interests in January 2009, to be implemented in January 2011. Sections 1601 and 1602 require all entities to report non-controlling interests in subsidiaries as equity on the Interim Consolidated Balance Sheet. In addition, Section 1602 requires entities to report net income and comprehensive income for both the controlling and non-controlling interests. We adopted Section 1601 prospectively and Section 1602 retrospectively as required. The Interim Consolidated Financial Statements and related information in this report, reflect the application of the reporting requirements of Sections 1601 and 1602.

Transition to United States Generally Accepted Accounting Principles (U.S. GAAP)

In February 2008, the Accounting Standards Board (AcSB) of the Canadian Institute of Chartered Accountants (CICA) confirmed that publicly accountable enterprises will be required to adopt International Financial Reporting Standards (IFRS) in place of GAAP for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011.

In September 2010, the AcSB offered an optional one year deferral to adopt IFRS for qualifying entities with rate regulated activities and permit such entities to continue to apply Part V – Pre changeover accounting standards of the CICA Handbook during that period. Union Gas is a qualifying entity for purposes of this deferral.

While our IFRS conversion project was on track to meet the original conversion deadline, we have elected to use the deferral offered by the AcSB. This decision was made to allow us to convert at the same time as many companies in our industry, and to review our options, including U.S. GAAP instead of IFRS.

At this time, we are taking the steps necessary to report under U.S. GAAP.

Conversion plan

Our U.S. GAAP conversion process started in April 2011. Throughout 2011 we will be capturing comparative figures and fully converting to U.S. GAAP on January 1, 2012. Employee training is being provided throughout the year and will continue beyond the transition process. The conversion to U.S. GAAP is not expected to have a significant impact on our financial systems and business activities.

Key accounting differences

The main area of difference in reporting under U.S. GAAP is pension accounting. We are currently assessing the impacts of pension accounting to our financial statements and expect to record a charge to accumulated other comprehensive income and retained earnings, and to recognize a regulatory asset in the opening balance sheet upon conversion to U.S. GAAP primarily a result of actuarial losses to be recorded under U.S. GAAP.

INTERIM CONSOLIDATED STATEMENTS OF INCOME AND COMPREHENSIVE INCOME

(unaudited)

For the Periods Ended June 30 ($millions)	Three Months Ended **2011**	2010	Six Months Ended **2011**	2010
Gas sales and distribution revenue	**276**	258	**875**	866
Cost of gas	**122**	113	**487**	500
Gas distribution margin	**154**	145	**388**	366
Storage and transportation revenue	**78**	74	**161**	155
Other revenue	**7**	8	**12**	14
	239	227	**561**	535
Expenses				
Operating and maintenance	**89**	87	**180**	178
Depreciation and amortization	**52**	50	**104**	100
Property and capital taxes	**16**	16	**32**	33
	157	153	**316**	311
Income before other items	**82**	74	**245**	224
Interest expense	**36**	39	**74**	78
Income before income taxes	**46**	35	**171**	146
Income taxes	**11**	7	**39**	33
Net income and comprehensive income	**35**	28	**132**	113
Preference share dividends	–	–	**1**	1
Net income applicable to common shares	**35**	28	**131**	112

(See accompanying notes)

INTERIM CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

(unaudited)

For the Periods Ended June 30 ($millions)	Six Months Ended **2011**	2010
Retained earnings, beginning of period	**710**	696
Net income and comprehensive income	**132**	113
Dividends		
Preference shares	**(1)**	(1)
Common shares	**(32)**	(32)
Retained earnings, end of period	**809**	776

(See accompanying notes)

INTERIM CONSOLIDATED BALANCE SHEETS

(unaudited)

($millions)	**June 30 2011**	December 31 2010	June 30 2010
Assets			
Current assets			
Cash and cash equivalents	**16**	12	1
Accounts receivable	**424**	516	348
Income taxes receivable	–	–	8
Inventories	**128**	174	193
Future income taxes	**1**	14	21
Total current assets	**569**	716	571
Property, plant and equipment			
Cost	**6,477**	6,370	6,260
Accumulated deprecation	**2,077**	1,994	1,966
Property, plant and equipment, net	**4,400**	4,376	4,294
Regulatory and other assets	**493**	493	450
Total Assets	**5,462**	5,585	5,315
Liabilities and Equity			
Current liabilities			
Short-term borrowings (note 3)	**12**	198	–
Commercial paper (note 4)	**30**	157	232
Accounts payable and accrued charges	**577**	586	630
Income taxes payable	**30**	8	–
Long-term debt (note 4)	–	250	287
Total current liabilities	**649**	1,199	1,149
Long-term liabilities			
Long-term debt (note 4)	**2,276**	1,978	1,730
Mandatorily redeemable preference shares	**5**	5	5
Future income taxes	**375**	361	339
Asset retirement obligations	**126**	123	114
Regulatory and other liabilities	**481**	468	460
Total long-term liabilities	**3,263**	2,935	2,648
Total Liabilities	**3,912**	4,134	3,797
Equity			
Share capital (note 5)	**732**	732	732
Retained earnings	**809**	710	776
Non-controlling interest	**9**	9	10
Total Equity	**1,550**	1,451	1,518
Total Liabilities and Equity	**5,462**	5,585	5,315

(See accompanying notes)

Approved by the Board

Director

Director

INTERIM CONSOLIDATED STATEMENTS OF CASH FLOWS

(unaudited)

For the Periods Ended June 30 ($millions)	Three Month Ended **2011**	2010	Six Months Ended **2011**	2010
Operating Activities				
Net income	**35**	28	**132**	113
Items not affecting cash				
Depreciation and amortization	**52**	50	**104**	101
Future income taxes	**11**	14	**9**	48
Changes in working capital	**27**	(41)	**169**	(76)
	125	51	**414**	186
Investing Activities				
Capital expenditures	**(63)**	(46)	**(114)**	(78)
Financing Activities				
Net decrease in short-term borrowings	**(88)**	–	**(186)**	–
Net increase (decrease) in commercial paper	**4**	196	**(127)**	193
Long-term debt issued	**300**	–	**300**	–
Long-term debt repayment	**(250)**	(185)	**(250)**	(185)
Dividends paid	**(16)**	(16)	**(33)**	(149)
	(50)	(5)	**(296)**	(141)
Change in cash and cash equivalents, during the period	**12**	–	**4**	(33)
Cash and cash equivalents, beginning of period	**4**	1	**12**	34
Cash and cash equivalents, end of period	**16**	1	**16**	1
Supplementary Disclosure of Cash Flow Information:				
Cash payments of interest	**37**	45	**77**	79
Cash payments of income taxes	–	12	**8**	95

(See accompanying notes)

UNION GAS LIMITED
NOTES TO INTERIM CONSOLIDATED FINANCIAL STATEMENTS
June 30, 2011
(unaudited)

1. Significant Accounting Policies

Accounting Principles

The interim consolidated financial statements of Union Gas Limited (Union Gas or the Company) have been prepared in accordance with Canadian generally accepted accounting principles (GAAP) except that the disclosures do not conform in all respects to the requirements for annual consolidated financial statements. These interim consolidated financial statements, which are unaudited, should be read in conjunction with the most recent annual consolidated financial statements and have been prepared from the records of the Company.

The preparation of interim consolidated financial statements in conformity 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.

The interim consolidated financial statements should not be taken as indicative of the performance to be expected for the full year due to the seasonal nature of the utility business. 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 weather variations relative to demand during the winter heating season.

The interim consolidated financial statements follow the same accounting policies as the most recent annual consolidated financial statements.

Accounting Estimates

The interim consolidated financial statements follow the same methods of computation as the most recent annual consolidated financial statements.

Accounting Changes

Consolidated Financial Statements and Non-controlling Interest

The Canadian Institute of Chartered Accountants (CICA) issued Section 1601, Consolidated Financial Statements and Section 1602, Non-controlling Interests in January 2009, to be implemented in January 2011. Sections 1601 and 1602 require all entities to report non-controlling interests in subsidiaries as equity on the Interim Consolidated Balance Sheet. In addition, Section 1602 requires entities to report net income and comprehensive income for both the controlling and non-controlling interests. We adopted Section 1601 prospectively and Section 1602 retrospectively as required. The Interim Consolidated Financial Statements and related information in this report, reflect the application of the reporting requirements of Sections 1601 and 1602.

2. Financial Statement Effects of Rate Regulation

The Company records the following assets and liabilities that result from the regulated ratemaking process that might not be recorded under GAAP for non-regulated entities.

($millions)	Financial Statement Location	Recovery/ Settlement Period	**June 30 2011**	December 31 2010	June 30 2010
Assets					
Other deferrals – current	a	A	**14**	12	27
Gas in storage inventory	b	A	**15**	28	58
Other deferrals – long-term	c	B	**1**	3	2
Future income taxes – long-term	c	B/C	**233**	214	178
Total assets			**263**	257	265
Liabilities					
Other deferrals – current	d	A	**24**	31	24
Gas cost deferrals	d	A	**26**	39	81
Storage deferrals	d	A	**5**	9	24
Asset removal costs	e	C	**419**	409	405
Total liabilities			**474**	488	534

In the absence of rate regulation, the Company's future income tax asset (current) would have been $6 million lower for the six months ended June 30, 2011 (December 31, 2010 - $20 million lower, June 30, 2010 - $32 million lower), and the future income tax liability (long-term) would have been $46 million higher for the six months ended June 30, 2011 (December 31, 2010 - $48 million higher, June 30, 2010 - $25 million higher) as a result of the elimination of the above regulatory assets and liabilities.

Financial Statement Location

(a) Accounts receivable
(b) Inventories
(c) Regulatory and other assets
(d) Accounts payable and accrued charges
(e) Regulatory and other liabilities

Recovery/Settlement Period

(A) Remaining recovery / settlement is less than 1 year
(B) Remaining recovery / settlement is from 2 to 10 years
(C) Remaining recovery / settlement is over the remaining life of the associated assets

Other deferrals – current

As prescribed by regulatory order, the Company has various amounts included in customer rates that are intended to recover specifically-identified costs. To the extent that the actual costs differ from forecast costs or revenues, the variance is deferred for future recovery from or refund to ratepayers. In the absence of rate regulation, after-tax earnings for the three and six months ended June 30, 2011 could have been unchanged and $6 million lower, respectively (June 30, 2010 - $2 million and $12 million lower, respectively) because GAAP for non-regulated entities would require that all customer rate revenue and costs be recognized in income when earned.

Gas in storage

Gas in storage is carried at the weighted average cost of gas as approved by the Ontario Energy Board (OEB). In the absence of rate regulation, after-tax earnings for the three and six months ended June 30, 2011 could have been $11 million lower and $13 million higher, respectively (June 30, 2010 – $40 million and $21 million lower, respectively), because GAAP for non-regulated entities would require that gas in storage be recorded at the lower of cost and net realizable value.

Future income taxes

The accounting standard related to income taxes requires rate-regulated enterprises to recognize future income tax assets and liabilities, and an associated regulatory asset or liability, if applicable, for the amount of future income taxes expected to be recovered from or refunded to ratepayers, and to present these amounts on a gross basis in the financial statements. In the absence of rate regulation, after-tax earnings for the three and six months ended June 30, 2011 could have been $4 million and $14 million lower, respectively (June 30, 2010 – $1 million and $12 million lower, respectively) because GAAP for non-regulated entities would require that these amounts be recognized in earnings in the current period.

Gas cost deferrals

The Company and the OEB have a mechanism in place to change gas commodity rates on a quarterly basis, to ensure that customers' rates reflect future expected costs 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. These deferred amounts are subject to review and approval by the OEB on an annual basis in the normal course. 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, after-tax earnings for the three and six months ended June 30, 2011 could have been $7 million higher and $9 million lower, respectively (June 30, 2010 – $17 million higher and $72 million lower, respectively), because GAAP for non-regulated entities would require that actual commodity costs be recognized as an expense when incurred.

Storage deferrals

The Company earns revenue for providing storage services to customers. The forecast of this revenue is one component used to establish Union Gas' rates for services. Storage deferral accounts accumulate any difference between the actual revenue earned in providing these storage 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 revenue be recognized in income when earned. After-tax earnings for the three and six months ended June 30, 2011 would be $3 million and $3 million lower, respectively (June 30, 2010 – $1 million and $3 million higher, respectively), if these transactions were accounted for under GAAP for non-regulated entities.

Asset removal costs

The Company has recorded a regulatory liability, included in deferred credits and other liabilities, as a result of estimated removal costs for property that does not have an associated legal retirement obligation. In the absence of rate regulation, these costs may not have been recorded and after-tax earnings for the three and six months ended June 30, 2011 could have been $3 million and $7 million higher, respectively (June 30, 2010 – $4 million and $5 million higher, respectively).

Property, plant and equipment

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

3. Related Party Transactions

During the six months ended June 30, 2011, the Company obtained from or provided to Westcoast Energy Inc. unsecured loans. The balance outstanding on these loans at June 30, 2011 was a $12 million payable (December 31, 2010 – $198 million payable, June 30, 2010 – $nil). These loans are classified as short-term borrowings at June 30, 2011.

4. Debt and Credit Facilities

Available Credit Facility and Restrictive Debt Covenants

	Expiration Date	**Credit Facility Capacity**	**Outstanding at June 30, 2011 Commercial Paper**
Multi-year syndicated[7]	2012	500	30

The issuance of commercial paper and other facility borrowings reduces the amount available under the credit facility.

The Company's credit agreement contains various financial and other covenants, including the maintenance of certain financial ratios. Failure to meet those covenants beyond applicable grace periods could result in accelerated due dates and/or termination of the agreement. As of June 30, 2011, the Company was in compliance with those covenants. In addition, the credit agreement allows for the acceleration of payments or termination of the agreement due to non-payment, or in some cases, due to the acceleration of other significant indebtedness of the borrower or some of its subsidiaries.

Debt Issuance

In June 2011, the Company issued $300 million of Series 9 medium-term note debentures at 4.88% per annum, due June 2041. Net proceeds from the offering will be used for general corporate purposes, including refinancing of the May 2011 retirement.

5. Share Capital

		Outstanding			
	Authorized	**June 30 2011**	June 30 2010	**June 30 2011**	June 30 2010
	(shares)	*(shares)*		*($millions)*	
Class A, Series B, 6%	90,000	**90,000**	90,000	**5**	5
Class B, Series 10, 4.88%	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, Series B Preference Shares are cumulative and redeemable at $55 per share at the option of the Company.

The Class B, Series 10 Preference Shares are cumulative and redeemable at $25 per share at the option of the Company and, at the option of the holders, convertible back into Series 11 shares every five years commencing January 1, 2014. Union Gas may redeem at any time all, but not less than all, of the outstanding Series 10

[7] Credit facility contains a covenant requiring the debt-to-total capitalization ratio to not exceed 75% and a provision which requires Union Gas to repay all borrowings under the facility for a period of two days during the second quarter of each year.

Shares. The dividend rate of the Series 10 Shares is floating at an annual rate equal to 80% of the prime rate until December 31, 2013.

6. Employee Future Benefits

	Three Months Ended June 30			
	Pension		**Other**	
($millions)	**2011**	2010	**2011**	2010
Net Benefit Costs				
Current service cost	**3**	3	–	–
Interest cost	**8**	8	**1**	1
Expected return on plan assets	**(9)**	(9)	–	–
Amortization of loss	**5**	3	–	–
Amortization of past service costs	–	1	–	–
Amortization of transitional obligation	**1**	1	**1**	1
Expected benefit plan expense	**8**	7	**2**	2
Defined contribution expense	**2**	1	–	–
Total net benefit cost	**10**	8	**2**	2

	Six Months Ended June 30			
	Pension		**Other**	
($millions)	**2011**	2010	**2011**	2010
Net Benefit Costs				
Current service cost	**6**	6	**1**	1
Interest cost	**16**	16	**2**	2
Expected return on plan assets	**(17)**	(17)	–	–
Amortization of loss	**10**	7	–	–
Amortization of past service costs	**1**	1	–	–
Amortization of transitional obligation	**1**	1	**1**	1
Expected benefit plan expense	**17**	14	**4**	4
Defined contribution expense	**3**	2	–	–
Total net benefit cost	**20**	16	**4**	4

The Company made total contributions to the registered defined benefit and defined contribution pension plans during the three and six months ended June 30, 2011 of $12 million and $22 million, respectively (June 30, 2010 - $11 million and $22 million, respectively). The Company anticipates that it will make total contributions of approximately $50 million to the registered defined benefit and defined contribution pension plans in 2011.

7. Financial Instruments

Under Canadian GAAP, financial instruments are classified into one of the following five categories: held-for trading, held to maturity investments, loans and receivables, available-for-sale financial assets and other financial liabilities.

The carrying value of the Company's financial instruments are classified into the following categories:

Classification

($millions)	**June 30 2011**	December 31 2010	June 30 2010
Financial assets held for trading[8]	**16**	12	1
Loans and receivables[9]	**197**	301	149
Other financial liabilities[10]	**2,568**	2,793	2,488

The fair values of the Company's financial instruments are not materially different from their carrying value, with the exception of the Company's long-term debt of $2,290 million at June 30, 2011 (December 31, 2010 – $2,240 million, June 30, 2010 – $2,027 million). Based on current interest rates for debt with similar terms and maturities, the fair market value is estimated to be $2,639 million at June 30, 2011 (December 31, 2010 – $2,610 million, June 30, 2010 – $2,345 million).

Fair value hierarchy

Financial instruments recorded at fair value on the Interim Consolidated Balance Sheet are valued using a fair value hierarchy that reflects the significance of the inputs used in making the measurements. The fair value hierarchy has the following levels:

Level 1 - valuation based on quoted prices (unadjusted) in active markets for identical assets or liabilities;

Level 2 - valuation techniques based on inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly (i.e. as prices) or indirectly (i.e. derived from prices);

Level 3 - valuation techniques using inputs for the asset or liability that are not based on observable market data (unobservable inputs).

The fair value hierarchy requires the use of observable market inputs whenever such inputs exist. A financial instrument is classified to the lowest level of the hierarchy for which a significant input has been considered in measuring fair value.

Cash and cash equivalents are the only financial instruments recorded at fair value on the Interim Consolidated Balance Sheet and are classified as level 1.

Interest rate risk

Interest rate risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market interest rates. The long-term debt bears interest at fixed rates and therefore the cash flow exposure is not significant. However, the fair value of loans having fixed rates of interest could fluctuate because of changes in market interest rates. The fair value of short-term borrowings have a limited exposure to interest rate risk due to their short-term maturity.

Credit risk

Credit risk is the risk of financial loss to the Company if a customer or counterparty to a financial instrument fails to meet its contractual obligation. The maximum exposure to credit risk of the Company at period end is the carrying value of its financial assets. The Company's principal customers for natural gas transportation and storage services are industrial end-users, marketers, local distribution companies and utilities. The Company's distribution customers are primarily industrial and residential end-users. These concentrations of customers may affect the Company's overall credit risk.

[8] Includes cash and cash equivalents
[9] Includes trade and other receivables
[10] Includes accounts payable and accrued charges, short-term borrowings, commercial paper, long-term debt, and mandatorily redeemable preference shares

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 June 30, 2011 is $87 million receivable (December 31, 2010 - $72 million receivable, June 30 2010 - $53 million receivable). 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.

The Company manages its credit risk on cash and cash equivalents by dealing solely with reputable banks and financial institutions. To manage its credit risk on accounts receivable, the Company performs ongoing credit reviews of all its customers. In cases where the credit quality of a customer does not meet the Company's requirements, a cash deposit, letter of credit or parental guarantee is required. Deposits held by the Company at June 30, 2011 amounted to $50 million (December 31, 2010 - $51 million, June 30, 2010 - $58 million). Significant financial difficulties of the debtor, the probability that the debtor will enter bankruptcy or financial reorganization, and default or delinquency in payments are considered indicators that the account receivable may be uncollectible and therefore should be included in the allowance for doubtful accounts.

Union Gas continues to utilize its established risk management policies and procedures to ensure the appropriate monitoring of customer credit positions and, based on current evaluations, does not expect any significant negative impacts associated with these positions.

The following table sets forth details of the age of trade receivables that are not impaired as well as the allowance for the doubtful accounts:

($millions)	**June 30 2011**	December 31 2010	June 30 2010
Current	**163**	284	118
30 Days over due	**15**	9	10
60 Days over due	**8**	3	5
90+ Days over due	**10**	6	11
Total trade accounts receivable	**196**	302	144
Allowance for doubtful accounts	**(6)**	(5)	(6)
Total trade accounts receivable, net[11]	**190**	297	138

For the quarters ended June 30, 2011 and 2010, no one customer accounted for more than 10% of sales or 10% of receivables.

Equity Price Risk

Our costs of providing non-contributory defined benefit retirement and postretirement benefit plans are dependent upon, among other things, rates of return on plan assets. These plan assets expose us to price fluctuations in equity markets. In addition, our captive insurance company maintains various investments to fund certain business risks and losses. Those investments may, from time to time, include investments in equity securities. Currently, we do not invest in equity securities other than employee benefits plan assets.

Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its obligations as they become due. The Company manages its liquidity risk by forecasting cash flows from operations and anticipated investing and financing activities. The Company has credit facilities available to help meet short-term financing needs (note 4).

[11] The carrying amount of accounts receivable is impacted by changes in gas prices, which may fluctuate significantly from year to year.

The following are the contractual maturities of the undiscounted cash flows of financial liabilities as at June 30, 2011:

($millions)	Total	2011	2012-2013	2014-2015	Thereafter
Short-term borrowings	12	12	–	–	–
Commercial paper	30	30	–	–	–
Accounts payable and accrued charges	577	577	–	–	–
Long-term debt (including principal and interest)	4,473	76	300	573	3,524
Mandatorily redeemable preference shares	5	–	–	–	5
Total	5,097	695	300	573	3,529

8. Capital Management

The Company's objectives in managing its capital include the continuation of its ability to serve customers and to generate the OEB allowed rate of return for its shareholders while maintaining the OEB-approved level of common equity.

In managing capital, management considers both debt and equity. The mix of debt and equity components is driven by prevailing market conditions, as the Company may take advantage of lower interest rates by issuing debt or utilizing available credit facilities. The Company is required by Undertakings to the Lieutenant Governor in Council of Ontario to maintain sufficient common equity at the level approved by the OEB. The quarterly dividend payment is determined to allow the Company to maintain the common equity component at the level approved by the OEB.

Various debt covenants require the Company's Indebtedness[12] not to exceed 75% of Total Capitalization[13].

As at June 30, 2011 and 2010, the Company was in compliance with the following externally imposed capital requirements. The Company monitors these requirements on a quarterly basis.

	June 30 2011	June 30 2010
OEB-approved minimum Common Equity	**36.00%**	36.00%
Allowed Return on Equity – regulated operations	**8.54%**	8.54%
Maximum Total Indebtedness to Total Capitalization	**75.00%**	75.00%
Actual Total Indebtedness to Total Capitalization	**60.00%**	59.80%

9. Guarantees

The Company has various financial guarantees which are issued in the normal course of business. The Company enters into these arrangements to facilitate a commercial transaction with a third party by enhancing the value of the transaction to the third party. To varying degrees, these agreements involve elements of performance and credit risk, which are not included on the Interim Consolidated Balance Sheet. The possibility of having to perform under these guarantees is largely dependent upon future operations of other third parties or the occurrence of certain future events. The Company's potential exposure under these agreements can range from a specific dollar amount to an unlimited dollar amount depending on the nature of the claim and the particular transaction. The Company is unable to estimate the total potential amount of future payments under these agreements due to several factors, such as unlimited exposure under certain guarantees.

[12] Indebtedness includes short-term borrowings, commercial paper, long-term debt, mandatorily redeemable preference shares and letters of credit.
[13] Capitalization includes shareholders-equity, non-controlling interest and indebtedness.

10. 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 could have a significant impact on its interim consolidated financial statements.

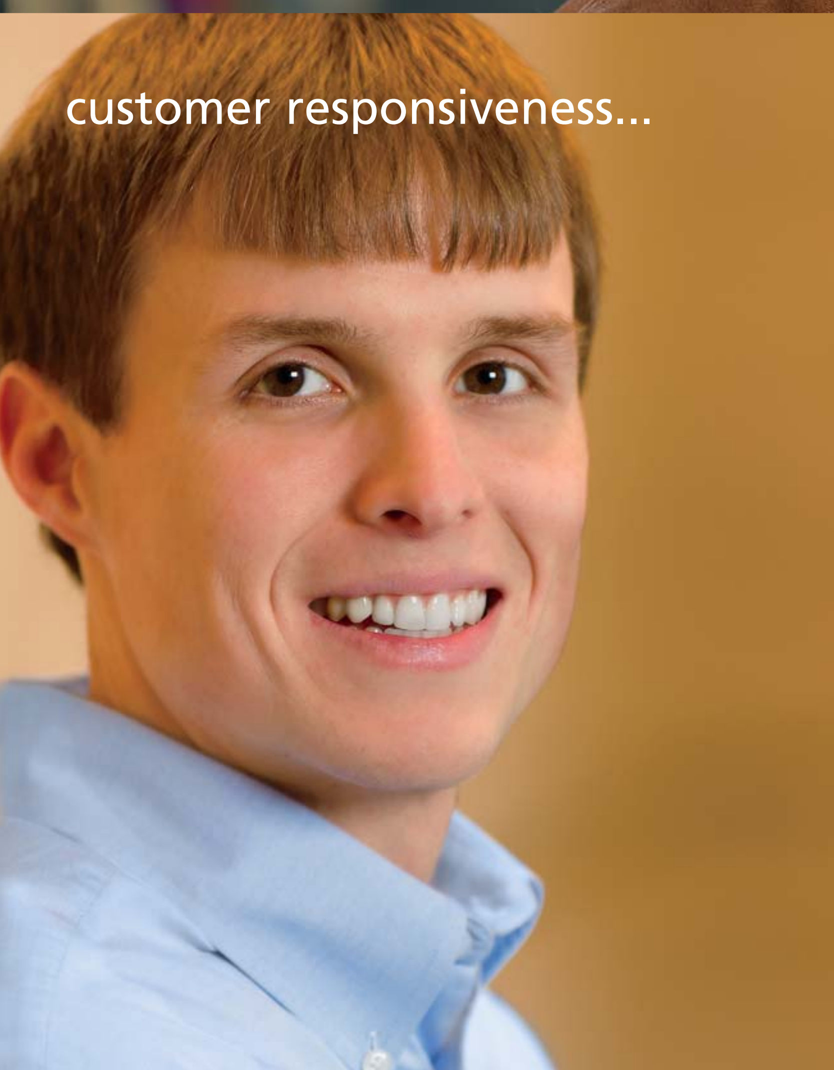
The Spectra Energy 2010 Annual Report is enclosed.

The Spectra Energy Corp Form 10-K for the period ended December 31, 2010 and the Spectra Energy Corp Form 10-Q for the period ended June 30, 2011 are available on Union's EB-2011-0210 website: http://www.uniongas.com/EB-2011-0210 - 2013 Rebasing.

Spectra Energy
2010 Annual Report

By 2012, we will be leading our sector in...

safety and reliability...



customer responsiveness...

and profitability.

Natural gas is a fuel whose time has come. It's reliable, clean-burning, domestically abundant and versatile. It stands ready to help address the environmental, economic and energy security needs of North America. So do we.

Spectra Energy delivers natural gas – a bountiful North American resource. We connect robust supply basins to growing demand markets in the U.S. and Canada. And we focus every day on serving the current and future needs of our valued stakeholders. This is our time. We're ready.

Contents

Spectra Energy Corp (NYSE: SE), a *FORTUNE 500* company, is one of North America's premier natural gas infrastructure companies serving three key links in the natural gas value chain: gathering and processing, transmission and storage, and distribution. For nearly a century, Spectra Energy and its predecessor companies have developed critically important pipelines and related infrastructure connecting natural gas supply sources to premium markets. Based in Houston, Texas, the company operates in the United States and Canada with approximately 19,000 miles of transmission pipeline and more than 305 billion cubic feet of storage, as well as natural gas gathering and processing, natural gas liquids operations and local distribution assets. The company also has a 50 percent ownership in DCP Midstream, one of the largest natural gas gatherers and processors in the United States. Spectra Energy is a member of the Dow Jones Sustainability World and North America Indexes and the U.S. S&P 500 Carbon Disclosure Project's Leadership Index for both Carbon Performance and Disclosure.

On the cover: Spectra Energy's goals are embraced and championed by more than 5,500 employees across North America. Shown on the cover, clockwise from top: Michael Terry, pipeliner working at East Tennessee Natural Gas System in Glade Spring, Virginia; Arvis Hagger, senior talent representative, corporate human resources; and Chris Harvey, lead certificates and rates representative, Northeast rates and certificates.

Our goal is clear:

By 2012, Spectra Energy will be leading the North American natural gas infrastructure sector in terms of safety and reliability, customer responsiveness and profitability. We will rely on an unparalleled network of assets and people to meet our customers' energy needs and deliver long-term value.

Letter from the President & CEO

"Tomorrow's energy imperatives are upon us. So are tremendous opportunities to invest, serve growing markets, create lasting value and help usher in a responsible new era in energy."

Letter to Shareholders

To our valued investors and stakeholders:

We are dedicating this annual report to describing our progress toward the goal of leading North America's natural gas infrastructure sector by 2012 in three vital areas: safety and reliability; customer responsiveness; and profitability.

We're looking forward because we believe in delivering energy today – and tomorrow. The signs are good: the economy is improving and the natural gas sector is strengthening at an even greater pace. As such, natural gas is positioned to play an increasingly important role in North America's energy future. These positive trends bode well for Spectra Energy investors.

Tomorrow's energy imperatives are upon us. So are tremendous opportunities to invest, serve growing markets, create lasting value and help usher in a responsible new era in energy. And we know that long-term, sustainable performance rests in our ability not only to deliver in the present, but to anticipate and act on what comes next. As our investors, you can be confident in the road ahead, because we are focusing on both the needs of today and the frontiers of opportunity ahead.

The fuel of choice

The second decade of the 21st century will become known as the era when natural gas was recognized as North America's 'fuel of choice.' In 2010, we witnessed and participated in productive discussion around the issues of energy security, infrastructure and the environmental impacts of energy consumption. While natural gas has long been a key contributor to North America's energy portfolio, it has recently moved to the forefront of public dialogue. Both the U.S. Senate and U.S. House of Representatives have established natural gas caucuses, focused on raising the profile of natural gas and advancing equitable legislative treatment. Similar advocacy efforts are under way in Canada, underlining growing government and private sector support for natural gas.

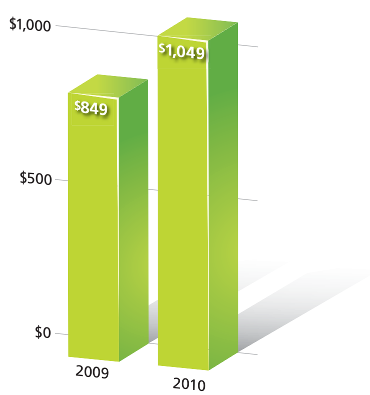
Natural gas is a fuel whose time has come. We are gratified that it is increasingly viewed as a near-term, viable option to reduce greenhouse gas emissions and deliver affordable and dependable energy to growing markets. Conservative estimates now point to 100-plus years of natural gas supply in North America, and that's good news for you, as an owner in one of the continent's largest, fastest-growing and most reliable natural gas infrastructure companies.

At Spectra Energy, we continue to solidify our position as 'advisor of choice,' providing leadership in numerous business and industry forums to address the energy policy issues and regulation that may affect our industry, our company and our stakeholders. Our employees understand the need to engage and have written thousands of letters to elected officials, citing the virtues of natural gas and urging them to take steps toward energy independence by making natural gas the fuel of choice for North America. Employees also encouraged members of the U.S. Congress to maintain lower taxation on the stock dividends that companies like Spectra Energy pay to investors like you. I want to thank our employees for their willingness to make their voices heard on issues important to our company, industry and future.

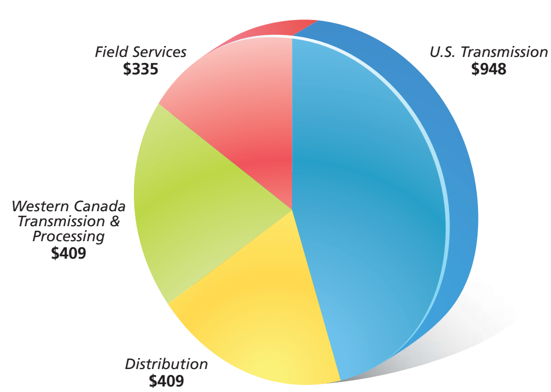
Financial Highlights

(In millions, except per share amounts and percentages)	**2010**	2009	2008
Common Stock Data			
Earnings per share			
Basic	**$ 1.62**	$ 1.32	$ 1.82
Diluted	**$ 1.61**	$ 1.32	$ 1.81
Dividends per share	**$ 1.00**	$ 1.00	$ 0.96
Shares outstanding			
Year-end	**649**	647	611
Weighted average – basic	**648**	642	622
Weighted average – diluted	**650**	643	624
Income Statement			
Operating revenues	**$ 4,945**	$ 4,552	$ 5,074
Total reportable segment EBIT	**2,101**	1,869	2,311
Net income – controlling interests	**1,049**	849	1,132
Balance Sheet			
Total assets	**$26,686**	$24,091	$21,924
Total debt	**11,320**	9,918	10,047
Capitalization			
Common equity – controlling interests	**39%**	40%	34%
Common equity – noncontrolling interests and preferred stock	**5%**	4%	4%
Total debt	**56%**	56%	62%
Capital and Investment Expenditures, including Acquisitions	**$ 1,848**	$ 1,336	$ 2,304

Net Income
in millions



2010 EBIT by Business Segment
in millions



Safe and reliable operations

Our license to operate rests with the public's trust in our ability to manage existing assets and construct new facilities to the highest safety standards. Nothing is more fundamental to our success or more compelling to our employees. We'll judge our progress toward the goal of leading our sector by 2012 in safety and reliability on metrics such as achieving top-decile performance in our employee injury frequency rate, and sector-leading performance in compression reliability, line break frequency, and bringing projects into service on time and on budget.

While we're not there yet, I'm pleased with the advances we are making toward our 'zero injury or work-related illness' goal. We achieved a significant overall improvement in our 2010 safety record, with a 30 percent decline in personal injuries among employees. We continue to identify process and performance changes aimed at protecting our employees, the communities in which we operate, and the environment. Although our employee injury numbers improved last year, we still have work to do in terms of reducing the number of vehicle incidents occurring across our business and ensuring that our contractors embrace our safe work practices as their own.

The priority we place on safe, reliable operations is evident in our annual commitment of capital to maintain our existing $17 billion in property, plant and equipment. Since 2007, we've invested more than half a billion dollars annually in maintenance and pipeline integrity. We work hard to ensure our assets are available to meet both the base and peak needs of customers, and in 2010 we achieved more than 99 percent transmission compression reliability across our system.

We pair market responsiveness and resource development with a profound sense of responsibility, and an eye toward long-term sustainability and being a 'partner of choice.' In 2010 we took steps to more closely manage our carbon footprint and reduce the environmental impacts of our operations. For the third consecutive year, Spectra Energy was named to the Dow Jones North America Sustainability Index. We were also named for the first time to the Dow Jones Sustainability World Index and led the energy sector on the 2010 Carbon Disclosure Project's Leadership Index.

We will know we're successful when we are the:

- *Supplier of choice for our customers*
- *Employer of choice for individuals*
- *Advisor of choice on policy and regulation for governments and regulators*
- *Partner of choice for our communities*
- *Investment opportunity of choice for investors*

Sustainability is also about the way we operate our business and care for the people affected by our operations. From hundreds of stakeholder meetings that help define our projects… to distributing 100,000 free energy saving kits per year to our Union Gas customers… to our annual Helping Hands in Action employee volunteer event – we listen and respond to communities across North America.

Our forward-looking philosophy applies to our employee team, and we commit significant focus to training, development and recruitment efforts to ensure we maintain our human capital advantage. We're working hard to ensure we are the 'employer of choice' for the men and women of Spectra Energy, and in 2010 we achieved a number of significant milestones: Spectra Energy was recognized as one of Houston's Top Workplaces; and Union Gas, our distribution business, was named one of Canada's Top 100 Employers. We were recently named one of Alberta's Top 50 Employers for 2011, and were proud to have our diversity efforts recognized with a 100 percent score on the Human Rights Campaign's 2011 Corporate Equality Index.

Customer responsiveness

We are proud to serve customers and communities across North America, and we measure our customer responsiveness success in terms of contract renewal rates across all our businesses, and connecting new and existing natural gas supply sources to growing markets.

We are connected to both conventional gas supply basins and prolific unconventional gas reserves like the Appalachian Basin's Marcellus, the Horn River and Montney in Western Canada, the Eagle Ford in South Texas and many others. Our businesses in the U.S. and Canada are ideally situated to serve the fastest-growing demand markets in North America, enabling us to move quickly on emerging opportunities.

That focus on being the 'supplier of choice' was evident in 2010, when we placed half a dozen pipeline, storage and processing growth projects into service on time and on budget, for a total investment of more than $900 million. Those facilities, ranging from Northeast British Columbia to Florida, Pennsylvania and Ontario, Canada, will provide returns well above expectations by adding some $200 million a year in new earnings before interest and taxes.

We also solidified our leading natural gas storage position in the Gulf Coast region by acquiring a new storage development that we will build out progressively through 2015. Upon completion, the Bobcat Storage project will provide customers with numerous options to reliably manage their needs in the Southeast U.S. And we reached a significant milestone on our New Jersey – New York project, with the filing of our certificate application late last year with the Federal Energy Regulatory Commission. We continue to make good progress on that important project, which will deliver new, affordable, clean-burning natural gas supplies to consumers in New Jersey and New York.

We see abundant opportunities ahead. Over the next five years we expect to invest at least $1 billion a year to be the 'supplier of choice' for both existing and new customers. Whether it's new infrastructure to serve the growing fleet of natural gas-fired generation in North America or new pipelines to bring domestic natural gas to factories and homes across the continent, Spectra Energy will be there.

Profitability

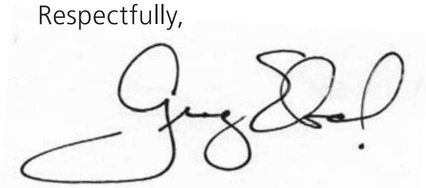
We know that as Spectra Energy investors, you're keenly interested in our ongoing profitability. We remain dedicated to growing our business and delivering a steady stream of value. I'm pleased by our record in this important area, and by our progress toward being the 'investment opportunity of choice' by leading our sector in profitability.

Our profitability metrics are straightforward: deliver a return on capital employed between 10 and 12 percent and rank within our sector's top quintile in total shareholder return. And, we are delivering. As investors, you realized a 2010 total shareholder return of 28 percent, compared with a 15 percent return from the S&P 500 and a 14 percent return from the Dow Jones Industrial Average. Between 2007 and 2010, we've invested $4 billion in capital expansion for an average annual return on capital employed of 14.5 percent. You would be hard pressed to find any of our peers who can match those results. And notably, we offer investors an attractive dividend, and true to our pledge to grow the dividend as we increase earnings, Spectra Energy's board of directors increased our quarterly dividend 4 percent, to 26 cents per share, effective in the first quarter of 2011.

We are exceptionally well positioned financially, with an investment-grade balance sheet, strong ongoing cash flow, ample liquidity and excellent access to capital. Spectra Energy offers investors a number of benefits – benefits detailed in the following pages. But perhaps our greatest appeal is the fact that we profitably deliver an essential product that stands ready to address important societal needs: the need for a reliable, secure, domestic energy source; the need for economic growth; and the need for a cleaner, sustainable environment. We believe today's investors increasingly recognize the long-term value of natural gas and share our commitment to delivering on its tremendous promise. We'll deliver on that promise – and on the goals we've set for 2012 and beyond.

We are grateful to you, our long-term investors, for your ongoing trust and support. We also appreciate the engagement of our chairman and board of directors, who champion your interests every day and inspire our management team to provide the best possible results for you, our investors.

Respectfully,



Gregory L. Ebel, *president and chief executive officer*

Letter from the Chairman

"Over the past several years, Spectra Energy has demonstrated its ability to excel in various market cycles and economic conditions, consistently delivering reliable, best-in-class service to customers and solid returns to shareholders."

Dear fellow investors:

As you've seen in the page of financial highlights, Spectra Energy delivered strong operating and financial results in 2010. Each of our major businesses generated solid results and growing cash flows. Your company has also made excellent progress on the major initiatives and goals we've established that will enable Spectra Energy to lead our industry and create lasting shareholder value.

Over the past several years, Spectra Energy has demonstrated its ability to excel in various market cycles and economic conditions, consistently delivering reliable, best-in-class service to customers and solid returns to shareholders. That record of reliability and resiliency readies us for the future – a future whose fuel of choice will be natural gas, delivered by Spectra Energy, North America's natural gas infrastructure company of choice.

I have great confidence in the men and women committed to securing that future: from president and CEO Greg Ebel, whose dedicated, dynamic leadership defines the company's high-performance culture…to an executive team who brings integrity and deep, diverse experience to every decision and action…to employees in field locations and offices across North America who work diligently on your behalf. The shared values of the Spectra Energy team shape the character of your company.

The people of Spectra Energy stand behind a strong, diverse portfolio of businesses, assets, geography and market position. The company is ideally positioned in both growing North American demand markets and established and emerging supply basins. The enviable scale and scope of our infrastructure assets would be nearly impossible to replicate today, making us uniquely poised to capture opportunities with speed and efficiency.

I am equally proud of Spectra Energy's record of serving communities in a responsible, sustainable manner. In his letter, Greg reports on the company's notable progress in serving the social, environmental and economic needs of communities across North America. The bar of expectations for sustainable performance rises every year, and the employees of Spectra Energy continue to deliver critically-needed energy infrastructure with a focus on safety, stewardship and community service.

Your board of directors is steadfastly committed to representing your needs and expectations. Our role is absolutely clear: to ensure that management best serves the long-term interests of shareholders and other stakeholders.

Toward that end, we've adopted principles of governance that ensure the board remains informed, independent and involved in your company. We work with your strong management team in reviewing course-setting strategy and the capital investments that will expand Spectra Energy's market presence and earnings capacity. We also assure that the corporation operates at the highest levels of transparency, compliance and ethical performance. We are vigilant in aligning CEO and executive compensation fairly and equitably in support of investor interests.

Your board met seven times in 2010. In January 2011, we were pleased to authorize a 4 percent increase in Spectra Energy's quarterly dividend, from $0.25 per share to $0.26 per share, effective in the first quarter of 2011. As earnings growth continues, we would expect to provide investors with future dividend increases consistent with the company's targeted payout ratio of 65 percent.

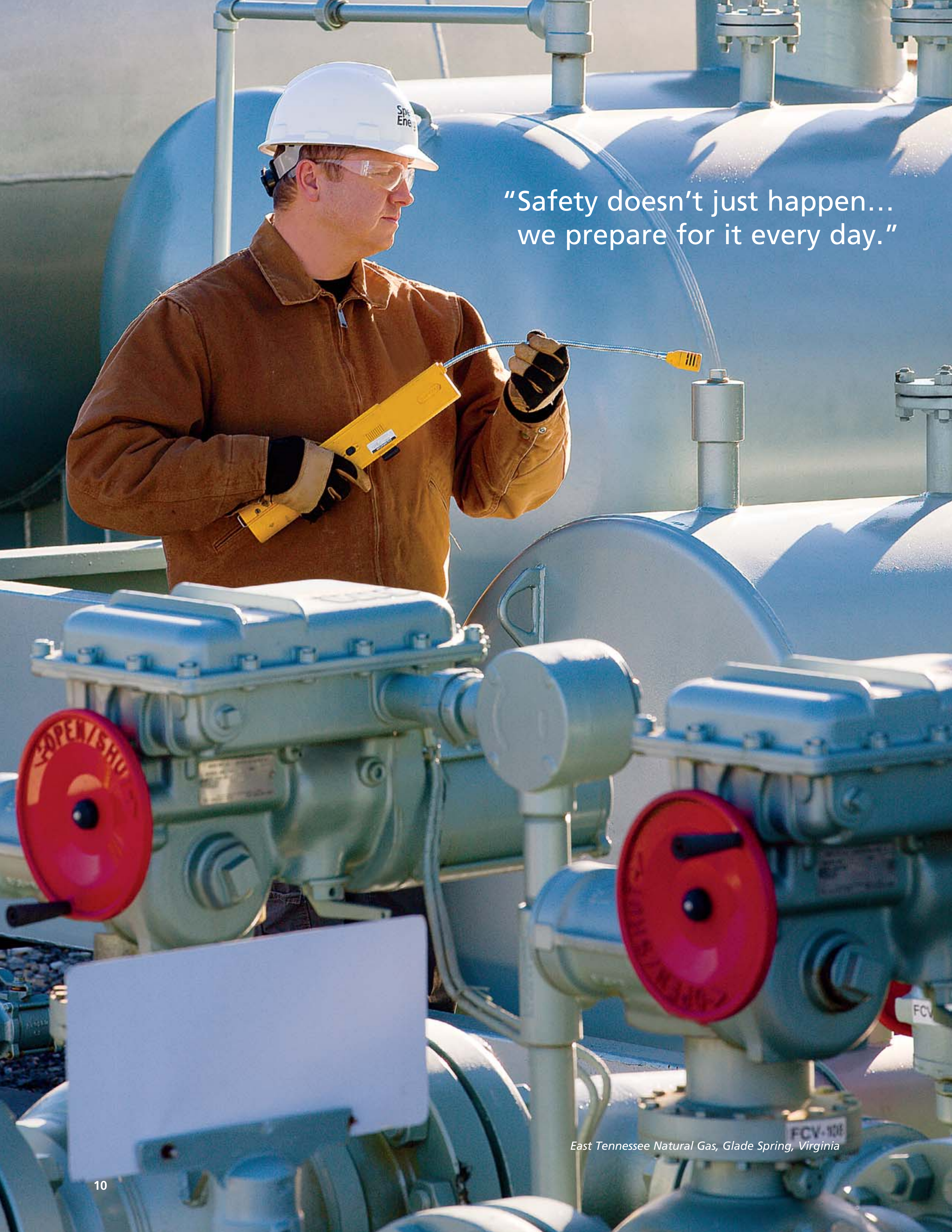
In 2010 we welcomed Joseph Netherland to our board. Joe is the former chairman of the board and CEO of FMC Technologies. He brings a wealth of business knowledge and petroleum industry experience to the company, and his wide-ranging expertise and keen insights are valuable assets to our board. With this addition, your board numbers 11 directors, who are fully committed to overseeing Spectra Energy's strategic direction and executive decision-making. We embrace that role and have great confidence in the direction, values and leadership of Spectra Energy.

This report is organized around the company's goal of leading its sector by 2012 in the areas of safety and reliability, customer responsiveness and profitability. There aren't many management teams willing to put such a tall and public stake in the ground – fewer still that I'd trust to succeed and surpass that goal. Based on their impressive record of execution and the solid foundation of management excellence, market insight, financial stability and solid values, I fully expect Greg and the Spectra Energy team to deliver on that pledge.

Thank you for sharing that confidence, and for your continued interest and support.

Bill Esrey

William T. Esrey, *chairman of the board*



"Safety doesn't just happen…
we prepare for it every day."

East Tennessee Natural Gas, Glade Spring, Virginia

Leading in Safety and Reliability

Spectra Energy is committed to being a safe and reliable operator, and to environmental stewardship in every region where we operate.

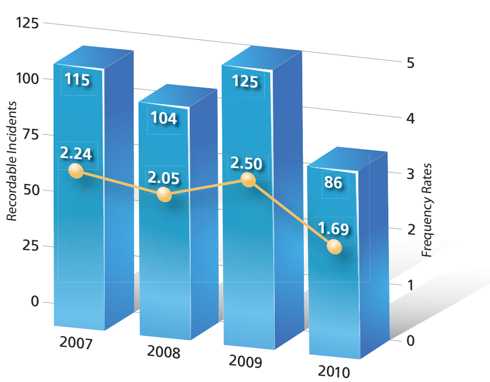
Our safety efforts are guided by the vision of a 'zero injury and zero work-related illness' culture for both employees and contractors. We're making progress toward that aspiration, realizing a 30 percent reduction in the number of employee injuries in 2010. But better is never good enough when it comes to safety, so we continue our unrelenting quest to improve, learn from mistakes and near misses, prevent recurrence and enhance processes that move us toward our zero goal.

We pursue the safety of the public and our facilities with vigor, committing between $500 to $700 million annually in maintenance capital to ensure our assets operate to the highest standards of safety, efficiency, reliability and customer service. Our maintenance program also helps us reduce methane emissions year after year through voluntary partnership with the U.S. Environmental Protection Agency's Natural Gas STAR Program.

We monitor our pipelines continuously, through round-the-clock electronic monitoring, regular air and ground surveillance and routine maintenance inspection. We maintain open and ongoing dialogue with our project and asset neighbors, and each year we mail more than 500,000 brochures to homeowners, businesses, potential excavators and public officials along our pipeline systems to inform them of the presence of pipelines and provide important safety information.

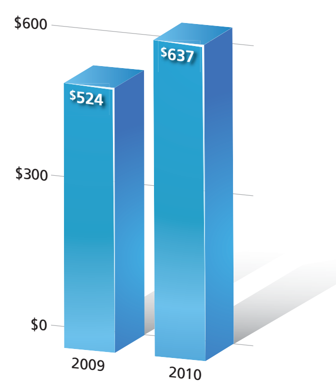
The greatest threat to natural gas pipeline integrity is inadvertent third-party excavation damage. Spectra Energy actively participates in U.S. and Canadian One-Call systems, centralized sources of information regarding the location of buried infrastructure. We are also a sponsor of the Common Ground Alliance, a non-profit organization dedicated to shared responsibility in damage prevention to ensure public safety, environmental protection and the integrity of critical infrastructure.

Employee Recordable Incidents & Frequency Rates



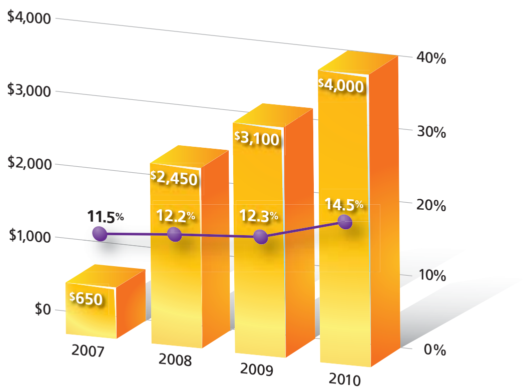
Note: Frequency rate = total number of employee incidents x 200,000 / total number of hours worked

Maintenance CapEx
dollars in millions



Pine River Processing Plant, British Columbia

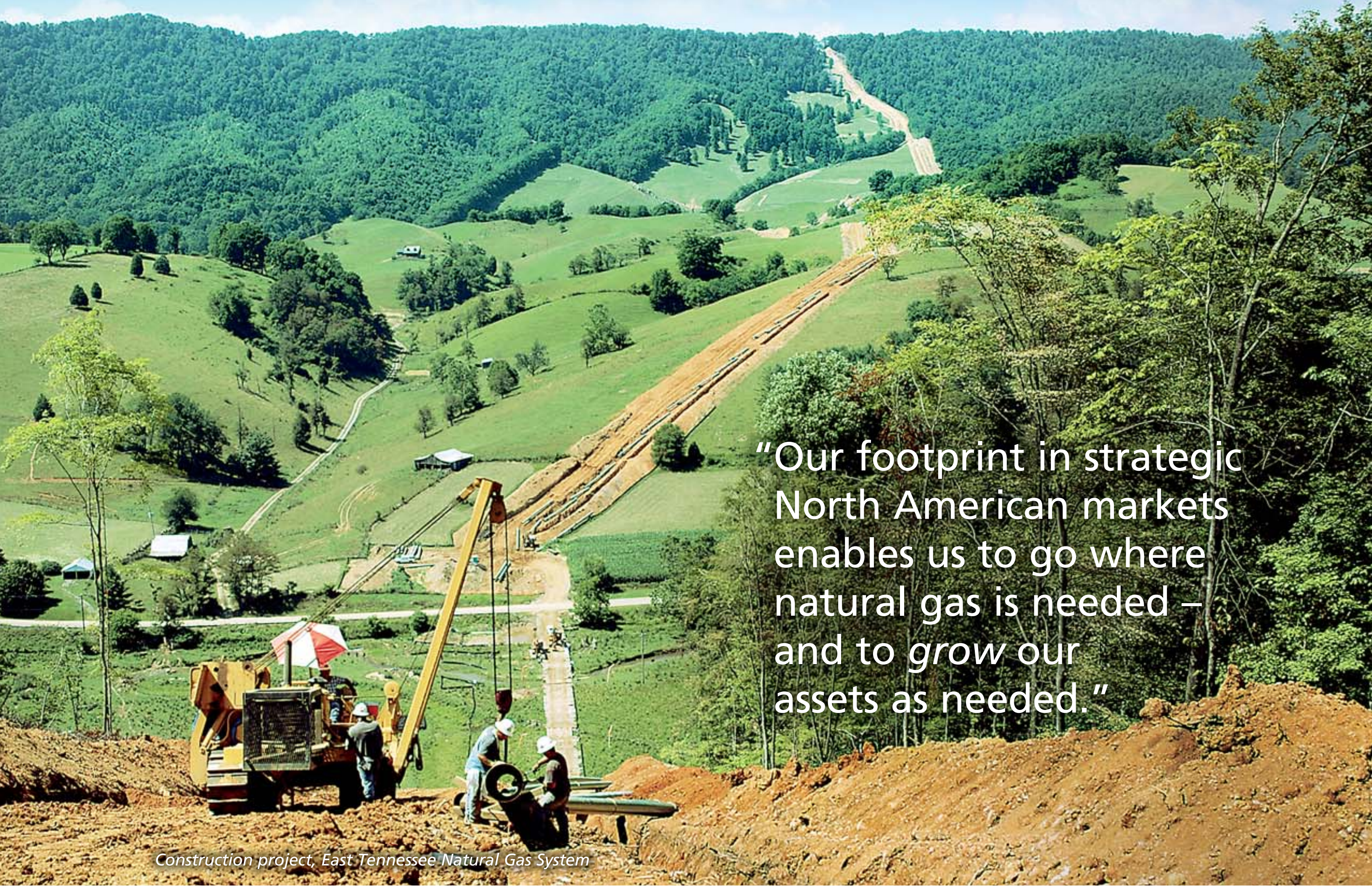
Expansion Projects: Cumulative Capital Investments & Return on Capital Employed
dollars in millions



Note: left rule depicts cumulative capital investment; right rule depicts return on capital employed

FREE Energy Saving Kit

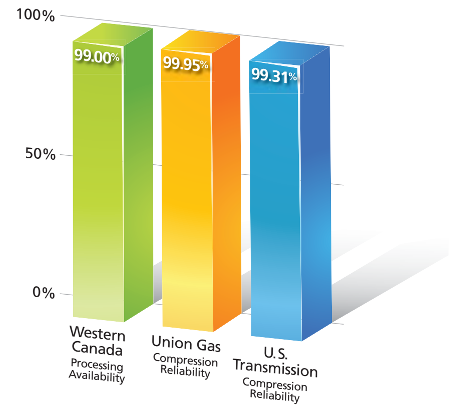
Helping Customers Save Dollars and Resources: Since 1997, Union Gas has helped customers save an estimated $1.6 billion through energy saving initiatives, including 820 million cubic meters of natural gas and 1.6 million tonnes of CO_2 emissions — the equivalent of taking more than 240,000 cars off North American roads.



Construction project, East Tennessee Natural Gas System

Leading in Customer Responsiveness

2010 Reliability Rates

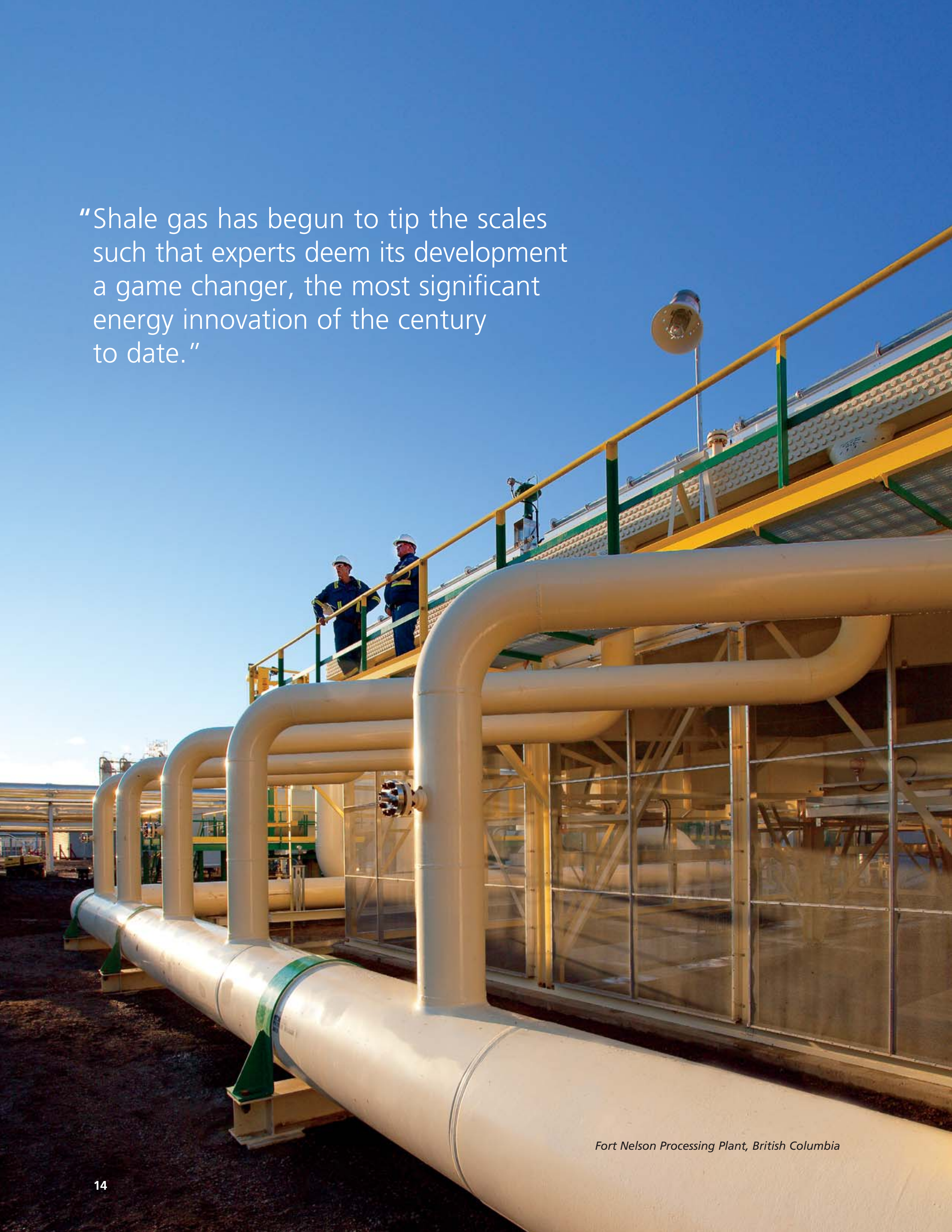


Spectra Energy serves a broad range of customers, including utilities, municipalities, energy merchants, producers and, through Union Gas, more than a million residential, commercial and industrial customers. We also serve the communities in which we operate through responsible corporate citizenship, volunteerism and focused corporate giving.

Our customer responsiveness is evident in our dedication to building and operating the energy infrastructure needed across North America. We're in the midst of an expansive capital program, committing more than $1 billion annually over the next five years, and in 2010 we brought into service projects like Algonquin East to West, which allows shippers to reach growing Northeast markets; the first phase of TEMAX/TIME III, which permits shippers to receive new natural gas supplies from Western U.S. basins along our Texas Eastern system; and nine of the 10 gathering and processing projects that make up our massive Fort Nelson expansion in Western Canada. Substantially all of our projects in execution and development are supported by long-term customer contracts.

With growth comes responsibility – responsibility that begins well before a project's launch, when we reach out to stakeholders, consult with regulators, elected officials and agencies, and partner with contractors who share our focus on safety and execution excellence. And our engagement continues throughout operation and as we contribute to the economic vitality and social fabric of the communities we serve through wages, taxes, philanthropic giving and volunteerism.

"Shale gas has begun to tip the scales such that experts deem its development a game changer, the most significant energy innovation of the century to date."



Fort Nelson Processing Plant, British Columbia

Leading in Profitability

At Spectra Energy, we look at every decision and opportunity through the lens of long-term value creation. Toward that end, efficient capital deployment is essential, and we're investing more than $1 billion annually to grow our business at industry-leading returns, increase earnings and deliver attractive dividends to our owners.

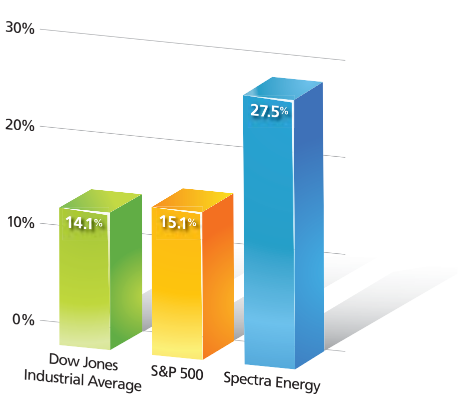
Between 2007 and 2010, we placed 47 fee-based expansion projects into service, totaling $4 billion of investment with returns on capital employed above 14.5 percent. Our future prospects are similarly compelling: in the next five years, we plan to invest about $5 billion in expansion projects and expect to realize incremental earnings before interest and taxes of $500 to $600 million for a return on capital employed in the 10 to 12 percent range.

We're well positioned financially, with an investment-grade balance sheet, strong cash flow, ample liquidity and excellent access to capital. Our strong credit ratings allowed us to take advantage of 2010's attractive debt market, and we issued more than $1 billion of debt at excellent rates.

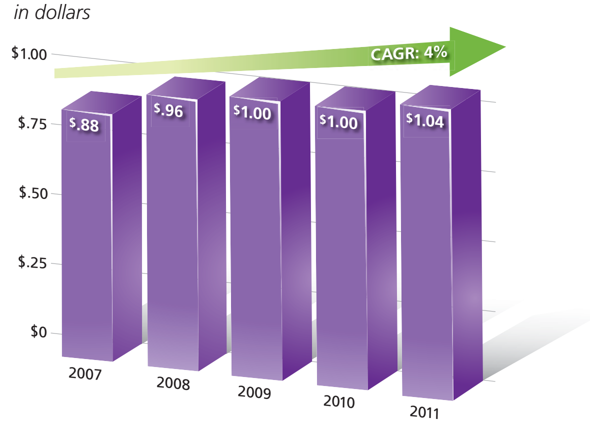
We continue to evaluate acquisition opportunities and in 2010 completed the acquisition of the Bobcat Storage facility, which further secures our premier storage position in the U.S. Gulf Coast.

We gain additional flexibility through our master limited partnership, Spectra Energy Partners, and in 2010 completed the drop down of substantially all of our remaining interest in the Gulfstream system to Spectra Energy Partners. And we have a strong, competitive business in DCP Midstream, our 50/50 joint venture with ConocoPhillips, which provided strong cash generation, investment returns and distributions of nearly $300 million to Spectra Energy during the year.

Total Shareholder Return 2010



Dividend Per Share Growth
in dollars



Condensed Consolidated Statements of Operations

(In millions, except per share amounts)	**2010**	2009	2008
	Years Ended December 31,		
Operating Revenues			
Transportation, storage and processing of natural gas	**$2,870**	$2,565	$2,343
Distribution of natural gas	**1,450**	1,451	1,731
Sales of natural gas liquids	**459**	389	772
Other	**166**	147	228
Total operating revenues	**4,945**	4,552	5,074
Operating Expenses			
Natural gas and petroleum products purchased	**1,056**	1,098	1,586
Operating, maintenance and other	**1,575**	1,406	1,481
Depreciation and amortization	**650**	584	569
Total operating expenses	**3,281**	3,088	3,636
Gains on Sales of Other Assets and Other, Net	**10**	11	42
Operating Income	**1,674**	1,475	1,480
Other Income and Expenses			
Equity in earnings of unconsolidated affiliates	**430**	369	778
Other income and expenses, net	**32**	37	66
Total other income and expenses	**462**	406	844
Interest Expense	**630**	610	636
Earnings From Continuing Operations Before Income Taxes	**1,506**	1,271	1,688
Income Tax Expense From Continuing Operations	**383**	352	493
Income From Continuing Operations	**1,123**	919	1,195
Income From Discontinued Operations, Net of Tax	**6**	5	2
Net Income	**1,129**	924	1,197
Net Income – Noncontrolling Interests	**80**	75	65
Net Income – Controlling Interests	**$1,049**	$ 849	$1,132
Earnings per Common Share			
Basic	**$ 1.62**	$ 1.32	$ 1.82
Diluted	**$ 1.61**	$ 1.32	$ 1.81
Dividends per Common Share	**$ 1.00**	$ 1.00	$ 0.96

Condensed Consolidated Balance Sheets

(In millions)	December 31, 2010	2009
ASSETS		
Current Assets		
Cash and cash equivalents	**$ 130**	$ 166
Receivables	**1,018**	778
Inventory	**287**	321
Other	**203**	164
Total current assets	**1,638**	1,429
Investments and Other Assets		
Investments in and loans to unconsolidated affiliates	**2,033**	2,001
Goodwill	**4,305**	3,948
Other	**665**	407
Total investments and other assets	**7,003**	6,356
Property, Plant and Equipment, Net	**16,980**	15,347
Regulatory Assets and Deferred Debits	**1,065**	959
Total Assets	**$26,686**	$24,091
LIABILITIES AND EQUITY		
Current Liabilities		
Accounts payable	**$ 369**	$ 333
Short-term borrowings and commercial paper	**836**	162
Current maturities of long-term debt	**315**	809
Other	**1,003**	1,191
Total current liabilities	**2,523**	2,495
Long-term Debt	**10,169**	8,947
Deferred Credits and Other Liabilities		
Deferred income taxes	**3,555**	3,209
Regulatory and other	**1,694**	1,634
Total deferred credits and other liabilities	**5,249**	4,843
Preferred Stock of Subsidiaries	**258**	225
Equity		
Controlling interests	**7,809**	7,041
Noncontrolling interests	**678**	540
Total equity	**8,487**	7,581
Total Liabilities and Equity	**$26,686**	$24,091

Condensed Consolidated Statements of Cash Flows

	Years Ended December 31,		
(In millions)	**2010**	2009	2008
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	**$ 1,129**	$ 924	$ 1,197
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	**664**	598	581
Deferred income tax expense	**205**	176	158
Equity in earnings of unconsolidated affiliates	**(430)**	(369)	(778)
Distributions received from unconsolidated affiliates	**391**	195	777
Changes in working capital	**(424)**	365	(168)
Other	**(127)**	(129)	38
Net cash provided by operating activities	**1,408**	1,760	1,805
CASH FLOWS FROM INVESTING ACTIVITIES			
Capital expenditures	**(1,346)**	(980)	(1,502)
Investments in and loans to unconsolidated affiliates	**(10)**	(61)	(528)
Acquisitions, net of cash acquired	**(492)**	(295)	(274)
Sales (purchases) of available-for-sale securities, net	**(216)**	32	124
Purchases of held-to-maturity securities	**(49)**	(121)	—
Net proceeds from the sales of other assets	**—**	—	105
Distributions received from unconsolidated affiliates	**17**	164	218
Receipt from affiliate – repayment of loan	**—**	186	—
Other	**(5)**	54	(6)
Net cash used in investing activities	**(2,101)**	(1,021)	(1,863)
CASH FLOWS FROM FINANCING ACTIVITIES			
Net increase (decrease) in short-term borrowings, commercial paper and long-term debt	**1,152**	(670)	1,406
Dividends paid on common stock	**(650)**	(631)	(598)
Proceeds from issuances of Spectra Energy Partners LP common units	**216**	208	—
Proceeds from issuance of Spectra Energy common stock	**—**	448	—
Repurchases of Spectra Energy common stock	**—**	—	(600)
Contributions from (distributions to) noncontrolling interests, net	**(73)**	(172)	45
Other	**11**	14	(39)
Net cash provided by (used in) financing activities	**656**	(803)	214
Effect of exchange rate changes on cash	**1**	25	(11)
Net increase (decrease) in cash and cash equivalents	**(36)**	(39)	145
Cash and cash equivalents at beginning of period	**166**	205	60
Cash and cash equivalents at end of period	**$ 130**	$ 166	$ 205

Condensed Consolidated Statements of Equity and Comprehensive Income

(In millions)	Common Stock/ Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income: Foreign Currency Translation Adjustments	Accumulated Other Comprehensive Income: Other	Noncontrolling Interests	Total
December 31, 2007	$4,604	$ 356	$ 2,026	$(216)	$ 581	$ 7,351
Net income	—	1,132	—	—	65	1,197
Other comprehensive income (loss)						
Foreign currency translation adjustments	—	—	(1,140)	—	(2)	(1,142)
Other, net	—	—	—	(144)	—	(144)
Total comprehensive income (loss)						(89)
Spectra Energy common stock repurchases	(600)	—	—	—	—	(600)
Dividends on common stock	—	(598)	—	—	—	(598)
Contributions from noncontrolling interests, net	—	—	—	—	42	42
Purchase of Spectra Energy Income Fund units	—	—	—	—	(208)	(208)
Other, net	46	—	—	—	(8)	38
December 31, 2008	4,050	890	886	(360)	470	5,936
Net income	—	849	—	—	75	924
Other comprehensive income						
Foreign currency translation adjustments	—	—	796	—	11	807
Other, net	—	—	—	(15)	—	(15)
Total comprehensive income						1,716
Dividends on common stock	—	(651)	—	—	—	(651)
Spectra Energy common stock issuance	448	—	—	—	—	448
Spectra Energy Partners LP common unit issuance	25	—	—	—	168	193
Distributions to noncontrolling interests, net	—	—	—	—	(172)	(172)
Other, net	123	—	—	—	(12)	111
December 31, 2009	4,646	1,088	1,682	(375)	540	7,581
Net income	—	1,049	—	—	80	1,129
Other comprehensive income						
Foreign currency translation adjustments	—	—	328	—	16	344
Other, net	—	—	—	(34)	—	(34)
Total comprehensive income						1,439
Dividends on common stock	—	(650)	—	—	—	(650)
Spectra Energy Partners LP common unit issuance	50	—	—	—	140	190
Distributions to noncontrolling interests, net	—	—	—	—	(73)	(73)
Other, net	31	—	—	(6)	(25)	—
December 31, 2010	**$4,727**	**$1,487**	**$ 2,010**	**$(415)**	**$ 678**	**$ 8,487**

Spectra Energy Board of Directors

William T. Esrey, Chairman

Bill Esrey chairs Spectra Energy's board of directors and is chairman emeritus of Sprint Corporation. He served as Sprint's chief executive officer from 1985 to 2003 and as that company's chairman from 1990 to 2003. He also served as chairman of Japan Telecom from 2003 to 2004. Esrey is a director of General Mills, Inc. Esrey serves on Spectra Energy's audit and corporate governance committees.

Austin A. Adams

Austin Adams is the former executive vice president and chief information officer (CIO) of JPMorgan Chase. He assumed that role in 2004, when JPMorgan Chase and Bank One Corporation merged. Before joining Bank One in 2001, Adams served as CIO for First Union Corporation. He is a director of NCO Group, owned by JPMorgan Private Equity, and Dun & Bradstreet Corporation. Adams is a member of Spectra Energy's audit and finance and risk management committees.

Paul M. Anderson

Paul Anderson served as chairman of Spectra Energy's board of directors from 2007 to 2009. He previously served in two executive roles with Duke Energy, as chairman of the board and earlier as president and chief operating officer. He also served as managing director and chief executive officer of BHP Billiton. Anderson also is a director of BP and BAE Systems. Anderson chairs Spectra Energy's finance and risk management committee.

Pamela L. Carter

Pamela Carter is president of Cummins Distribution Business. She previously served as president of Cummins Filtration, as vice president and general manager of Cummins' Europe, Middle East and Africa business and operations, and as vice president and general counsel for Cummins Inc. Prior to joining Cummins, she practiced law in the private sector and served as attorney general for the State of Indiana from 1993 to 1997. Carter is a member of the Export-Import Bank of the United States' Sub-Saharan Africa Advisory Council and a director of CSX Corporation. She is a member of Spectra Energy's compensation and corporate governance committees.

F. Anthony Comper

Tony Comper is the retired president and chief executive officer of BMO Financial Group. He was appointed to that position in February 1999 and served as chairman from July 1999 to May 2004. He previously served on the board of directors of the Bank of Montreal. Comper is a member of Spectra Energy's compensation and finance and risk management committees.

Gregory L. Ebel

Greg Ebel is president and chief executive officer of Spectra Energy. He previously served in a number of leadership roles for Spectra Energy and its predecessor companies, including chief financial officer; president of Union Gas; vice president of investor and shareholder relations; managing director of mergers and acquisitions; and vice president of strategic development. Ebel also is a member of DCP Midstream's board of directors.

Peter B. Hamilton

Peter Hamilton is the senior vice president and chief financial officer of Brunswick Corporation. He previously served Brunswick in a number of executive leadership capacities, including vice chairman, Brunswick Corporation; president, Brunswick Boat Group; president, Life Fitness Division; and president, Brunswick Bowling & Billiards. Hamilton chairs Spectra Energy's audit committee and also serves on the corporate governance committee.

Dennis R. Hendrix

Dennis Hendrix is the retired chairman of the board of PanEnergy Corp. He served as chairman from 1990 to 1997, as chief executive officer from 1990 to 1995 and as president from 1990 to 1993. He has served as a director of Duke Energy, Allied Waste Industries and Newfield Exploration Company. Hendrix chairs Spectra Energy's corporate governance committee and is a member of the compensation committee.

Michael McShane

Mike McShane is the former chairman, president and chief executive officer of Grant Prideco, Inc. He previously served as senior vice president of finance, chief financial officer and director of BJ Services Company. McShane is a director of Complete Production Services, Inc., Oasis Petroleum, Inc., and additionally serves on the board of directors for two private companies. He also serves Advent International as an advisor. McShane is a member of Spectra Energy's audit and finance and risk management committees.

Joseph H. Netherland

Joe Netherland served as chairman of FMC Technologies from December 2001 until his retirement in 2008. He also served as president of FMC Technologies from 2001 to 2006 and as chief executive officer from 2001 to 2007. He remains a director of FMC Technologies, and serves on the boards of Newfield Exploration Company and Tidewater Inc. He also serves as an advisory director of CVC Capital Partners. Netherland serves on Spectra Energy's compensation and corporate governance committees.

Michael E.J. Phelps

Michael Phelps is chairman of Dornoch Capital Inc., a private investment company. He served as president and chief executive officer of Westcoast Energy Inc. from 1988 to 1992 and as chairman and chief executive officer until 2002. He is a director of Canadian Pacific Railway Company, Prodigy Gold Inc. and Marathon Oil Corporation. Phelps chairs Spectra Energy's compensation committee and is a member of the finance and risk management committee.

Spectra Energy Leadership Team

Greg Ebel is president and chief executive officer and a member of the company's board of directors. He also serves on the board of directors of DCP Midstream.

Dorothy Ables is chief administrative officer, responsible for the company's information technology, audit services, human resources and community relations functions.

John Arensdorf is chief communications officer. He directs the company's communications with internal and external audiences, including investors, the media, employees and other stakeholders. He also oversees Spectra Energy's sustainability efforts.

Doug Bloom is president of the company's Western Canada operations, responsible for the company's western-based divisions: BC Pipeline, BC Field Services, Midstream and the Natural Gas Liquids division.

Julie Dill is president of Union Gas, one of Ontario's largest natural gas utilities. Union Gas also provides natural gas storage and transportation services to other utilities and energy market participants in Ontario, Quebec and the U.S.

Mark Fiedorek is group vice president of Southeast U.S. Transmission and Storage. He is responsible for the southern portion of Texas Eastern Transmission, East Tennessee Natural Gas, Steckman Ridge, Gulfstream Natural Gas, Southeast Supply Header, Market Hub Partners and Bobcat Storage. Fiedorek also serves on the board of directors of the company's publicly traded master limited partnership, Spectra Energy Partners.

Alan Harris is chief development and operations officer. He oversees the company's strategy, planning, corporate development and merger and acquisition activities, as well as project execution, the operations of Spectra Energy's U.S. pipeline and storage business, environment, health and safety, procurement and Spectra Energy Partners, the company's master limited partnership. He also serves on the board of directors for DCP Midstream Partners.

Reggie Hedgebeth is general counsel. As chief legal officer, he leads the company's legal and corporate secretary functions, as well as ethics and compliance, regulatory affairs and government relations.

Pat Reddy is chief financial officer. He leads the finance function, which includes the controller's office, treasury, tax, risk management and insurance. He also serves on the board of directors for DCP Midstream.

Bill Yardley is group vice president of Northeast U.S. Transmission. He is responsible for the company's Northeast U.S. assets, which include the northern portion of Texas Eastern Transmission, Algonquin Gas Transmission and Spectra Energy's interest in Maritimes & Northeast Pipeline.

Spectra Energy's Leadership Team:
The members of Spectra Energy's executive leadership team, from left:
Alan Harris, John Arensdorf, Greg Ebel, Julie Dill, Bill Yardley,
Mark Fiedorek, Dorothy Ables, Reggie Hedgebeth, Pat Reddy and Doug Bloom.

Shareholder Services

BNY Mellon Shareowner Services is the Transfer Agent and Registrar for Spectra Energy Corp common stock. Registered shareholders may direct questions about stock accounts, legal transfer requirements, address changes, dividend checks, lost certificates or other services by calling toll free 1-866-406-6840 (U.S. and Canadian callers) or 1-201-680-6578 (international callers).

Please send written requests to:

Spectra Energy Corp
c/o BNY Mellon Shareowner Services
480 Washington Blvd.
Jersey City, NJ 07310

For electronic correspondence, visit the BNY Mellon Shareowner Services Web site at www.bnymellon.com/shareowner/isd.

Stock Exchange Listing

Spectra Energy's common stock is listed on the New York Stock Exchange under the trading symbol SE.

Stock Purchase and Dividend Reinvestment Plan

The Spectra Energy Stock Purchase and Dividend Reinvestment Plan provides a simple and convenient way to purchase common stock directly through the company, without incurring brokerage fees. The Plan provides for full reinvestment, direct deposit or cash payment of dividends. Purchases may be made weekly. Additional options include bank drafts for monthly purchases and depositing certificates into the Plan for safekeeping. Visit the BNY Mellon Shareowner Services Web site at www.bnymellon.com/shareowner/isd for account management access.

Financial Publications

Spectra Energy's Securities & Exchange Commission reports and related financial publications can be found on our Web site at www.spectraenergy.com/investors. Printed copies are available on request.

Electronic Delivery

Spectra Energy encourages shareholders to enroll in electronic delivery of financial information and proxy statements. To enroll in electronic delivery, go to http://enroll.icsdelivery.com/se.

Duplicate Mailings

If your shares are registered in different accounts, you may receive duplicate mailings of annual reports, proxy statements and other shareholder information. Contact BNY Mellon Shareowner Services for instructions on how to combine your accounts or eliminate duplicate mailings.

Dividend Payment

Dividends on common stock are expected to be paid in March, June, September and December 2011, subject to declaration by the board of directors.

Web Site

Additional investor information may be obtained on Spectra Energy's Web site at www.spectraenergy.com.

Bond Trustee

If you have questions regarding your bond account, please call 1-800-254-2826, or address written correspondence to:

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UNION GAS LIMITED

RECONCILIATION OF UTILITY FINANCIAL RESULTS WITH THE UNION GAS FINANCIAL REPORTS

2010 Actual	-	See Exhibit F6, Tab 2, Schedule 1
2011 Actual	-	See Exhibit F5, Tab 2, Schedule 1
2012 Forecast	-	See Exhibit F4, Tab 2, Schedule 1
2013 Forecast	-	See Exhibit F3, Tab 2, Schedule 1

UNION GAS SUBSIDIARIES

Union Gas holds a 75% ownership interest in Huron Tipperary Limited Partnership I.

Union Gas has no other subsidiaries.

UNION GAS LIMITED

DBRS Report

Rating Report

Report Date:
January 31, 2011

Previous Report:
October 19, 2009

Insight beyond the rating.

Union Gas Limited

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The Company

Union Gas Ltd. is a utility that provides natural gas distribution (~69% of total revenues) and transmission and storage services (~28%) in southwestern, northern and eastern Ontario, serving approximately 1.3 million customers. The Company is a direct, wholly owned subsidiary of Westcoast Energy Inc. (rated A (low), Stable), which is indirectly owned by Spectra Energy Capital, LLC (rated BBB (high), Stable).

Commercial Paper Limit

$500 million

Recent Actions

July 20, 2010
$250 Million New Issue

Rating

Debt	Rating	Rating Action	Trend
Unsecured Debentures/Medium-Term Note Debentures	A	Confirmed	Stable
Commercial Paper	R-1 (low)	Confirmed	Stable
Cumulative Redeemable Preferred Shares	Pfd-2	Confirmed	Stable

Rating Rationale

DBRS has confirmed the Unsecured Debentures/Medium-Term Note Debentures (MTNs), Commercial Paper and Cumulative Redeemable Preferred Share ratings of Union Gas Limited (Union or the Company) at "A", R-1 (low) and Pfd-2, respectively, all with Stable trends. The ratings reflect Union's low business risk operations within a stable regulatory environment, dominant position within a strong franchise area, sound financial profile and credit metrics as well as earnings growth from its storage facilities and transmission system. The ratings also reflect the Company's exposure to ongoing volume risk and a continued modest decline in customer consumption, as well as cash flow deficits due principally to working capital changes, growing contribution of revenues from the unregulated portion of its business and the low allowed ROE under which Union must operate until 2012.

The regulatory environment for Union remains stable and continues to allow the Company to recover prudently incurred operating expenses and capital expenditures in a timely fashion. Union is currently operating under an Ontario Energy Board (OEB) approved five-year incentive regulation (IR) plan wherein the Company's distribution rates are adjusted annually based on the previous year's revenue and a number of adjustment factors. Union's allowed ROE of 8.54% is applicable for the duration of the IR framework until 2012 and its next cost-of-service rebasing for the subsequent period will be in 2013. (Continued on page 2.)

Rating Considerations

Strengths

(1) Low business risk operations within a stable regulatory environment
(2) Stable financial profile and credit metrics
(3) Dominant market position within a strong service area
(4) Additional earnings growth from storage facilities and transmission systems

Challenges

(1) Volume risk and decline in customer usage
(2) Growing contribution from unregulated business segment
(3) Low allowed ROE
(4) Cash flow deficits

Financial Information

Union Gas Limited	LTM	FYE Dec. 31st				
	Sept. 30/10	2009	2008	2007	2006	2005
EBIT/Interest Expense	2.40x	2.41x	2.47x	2.24x	1.90x	2.09x
Fixed-Charge Coverage	2.29x	2.30x	2.35x	2.13x	1.81x	1.99x
Debt/Cap	61.3%	61.1%	64.3%	61.7%	63.6%	64.0%
Cash Flow/Debt	16.6%	14.0%	14.6%	14.7%	7.8%	13.7%
Cash Flow/CapEx	2.12x	1.28x	0.92x	0.87x	0.50x	1.27x
Approved ROE	8.54%	8.54%	8.54%	8.54%	9.63%	9.62%
Net Income (before extra & pfd. divs.) ($MM)	180.0	177.0	177.0	140.0	102.0	120.0
Operating Cash Flow (after pfd. divs.) ($MM)	396.0	315.0	372.0	323.0	171.0	293.0

Union Gas Limited

Report Date:
January 31, 2011

Rating Update (Continued from page 1.)

The IR framework provides a measure of regulatory stability that underpins Union's predictable cash flow. However, DBRS notes that the original IR mechanism initially included a provision under which the Company was required to file for a review of the IR if its actual ROE was above/below 300 basis points of the expected level. Subsequently, when Union achieved normalized earnings for 2008 that exceeded the 300 basis point limit, it complied and filed for a review with the OEB. In June 2009, as a result of this application, an OEB approved agreement between Union and its stakeholders replaced the mandatory review provision with a 90/10 cost-sharing mechanism (in favour of customers).

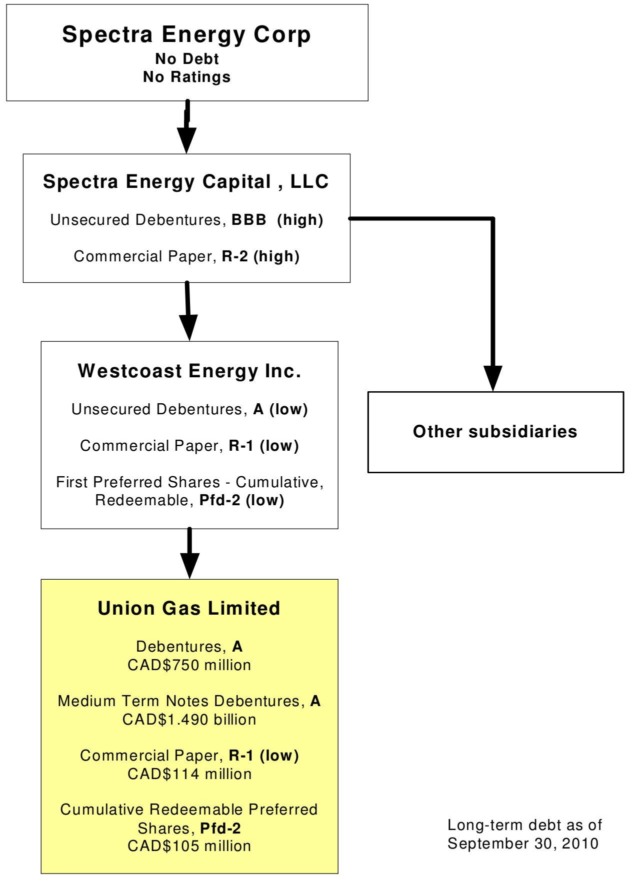
More recently, in September 2010, Union applied for approval of 2011 regulated distribution, storage and transmission rates, effective January 1, 2011. The proposed delivery rate increase of less than 1% for typical residential customers is predominantly attributable to the removal of long term storage revenues from delivery rates pursuant to the OEB's Natural Gas Electricity Interface Review decision.

Union continues to benefit from a large customer base that generates strong and stable cash flows, however, the Company remains exposed to a degree of demand risk since its rates are based on forecast volumes that are sensitive to changes in weather, economic conditions, pricing of competitive energy sources and declines in customer usage. The downturn in the Ontario manufacturing sector and overall economy will continue to place downward pressure on volumes in Union's franchise area. However, this is partially mitigated by the relatively low price of gas which supports its competitiveness relative to other energy sources (e.g., electricity). The Company has stated that it expects a continued reduction in industrial demand for natural gas as a result of industrial and commercial production slowdowns and industrial plant closures in Ontario.

Union's storage facilities continue to benefit from its strategic location at Dawn, the major natural gas hub in Ontario, which is connected to key pipelines and allows the Company to access other major Canadian and U.S. markets. The Company is expected to continue to expand its unregulated storage and regulated transmission businesses in the near- to medium-term and as such, DBRS expects earnings growth in this segment to outpace growth in the Company's gas distribution segment as it experiences overall decline in total gas consumption in its service area due to energy conservation. DBRS notes that natural gas continues to enjoy a competitive advantage in Ontario relative to alternative sources of energy, notably electricity which is more costly.

The Company will likely experience negative free cash flow for the year ending 2010 as a result of higher capital expenditures and working capital changes, the latter driven in part by gas cost deferrals. Although Union is not presently engaged in any major expansion projects, DBRS believes that should the Company embark on any sizable undertakings, it will finance its capital projects in a manner that will ensure that it maintains a stable balance sheet and credit metrics appropriate for its rating category. Furthermore, DBRS anticipates that, if necessary, Union's parent company, Westcoast Energy Inc., will provide financial support to the Company in the form of equity injections and/or reduced dividends to maintain its capital structure at the approved levels. Accordingly, overall, DBRS views Union's liquidity level as sufficient for its external funding requirements and current ratings.

Organizational Chart



Long-term debt as of September 30, 2010

Rating Considerations Details

Strengths

(1) Union's low-risk business operations generate stable operating cash flows and long-term earnings. Furthermore, the Company operates in a stable, supportive regulatory environment that allows it to recover prudently incurred operating expenses and capital expenditures in a timely matter and earn a reasonable return on its investments. This cost-of-service methodology combined with IR framework provides the necessary regulatory oversight required to underpin Union's predictable cash flow.

(2) Union's credit metrics have remained stable and appropriate for its ratings category, with leverage ratios remaining below 65% and EBIT/Interest Expense at 2.40x for the 12 months ending September 30, 2010. As the Company is committed to maintaining its common equity level in line with the 36% level approved by the OEB and its 8.54% ROE will remain unchanged for the duration of the IR period until 2012, Union's financial profile is expected to remain stable in the near- to medium-term.

(3) Union is one of the largest natural gas distributors in Canada and provides distribution, storage or transportation services to all gas fired generation plants in Ontario. Moreover, the Company's transmission and distribution system operates within a robust service territory, with roughly 1.3 million residential, commercial and industrial customers in more than 400 communities in northern, southwestern and eastern Ontario. Approximately 45% of this customer base is residential in nature which provides a degree of predictability with respect to energy demand and earnings. Union is subject to regulation by the OEB and as such, the Company's dominant market position may be primarily

attributed to the fact that it is generally not subjected to third party competition within its distribution franchise area.

(4) Union's Dawn Storage facility, comprised of approximately 150 billion cubic feet of capacity, is the largest natural gas storage facility in Canada and is strategically connected to key pipelines that allow Union to transmit natural gas to other major Canadian and U.S. markets. The Company's continued expansion of its unregulated storage capacity is anticipated to provide additional earnings growth potential over the medium term as well as enable the Company to better manage gas inventory and thus increase operational flexibility.

Challenges
(1) Union is exposed to a degree of demand risk since its rates are based on forecast volumes, which are sensitive to changes in weather, economic conditions, natural gas prices and declines in customer usage. Weak economic recovery and the downturn in Ontario's manufacturing sector will continue to place downward pressure on volumes in the Company's franchise area. This is partially mitigated by the historically low price of gas, which supports its competitiveness relative to other energy sources. The Company has stated that it expects a reduction in industrial demand for natural gas as a result of production slowdowns and a continued increase in industrial plant closures in Ontario.

(2). Union's intention to pursue growth opportunities in its unregulated storage segment may result in some earnings volatility and an incremental increase in its business risk profile should the proportion of revenue from this segment grow to comprise a significant portion of overall earnings. While DBRS believes that Union's low business risk profile and the regulatory oversight under which the Company operates considerably limits the bulk of any potentially deleterious effects of pursuing these unregulated growth opportunities, a shift towards increased volatility and risk may further soften already weak credit metrics. Currently, the unregulated portion of Union's storage business comprises approximately one-third of its storage capacity and as such, DBRS does not view the unregulated earnings as materially impactful at this time.

(3) The IR framework has set a low base level for Union's allowed ROE at 8.54% until year-end 2012. Thus, while the Company has the opportunity to earn higher returns, any upside is capped by the nature of the IR mechanism. Low ROEs have a negative impact on earnings and cash flow, although an increasing rate base would partially mitigate this impact.

(4) Union is anticipated to continue to generate modest but manageable free cash flow deficits in 2010 due mainly to increased working capital changes as a result of gas cost deferrals. In general, DBRS expects that the Company's free cash flow deficits be funded through a combination of dividend management and incremental debt in such a way that the Company maintains its approved capital structure.

Regulation

Regulatory Overview
Union's gas storage, transmission and distribution businesses are regulated by the OEB. However, rates for storage services to customers outside of Union's franchise area and rates for new storage services to customers within Union's franchise area are not regulated by the OEB.

During 2009, approximately one-third of customers within Union's service area purchased their gas supply from other suppliers and marketers. Since the Company earns income from the distribution of natural gas and not the sale of natural gas as a commodity, the Company's distribution margin is not adversely affected by this practice.

Gas Distribution
Union's distribution rates are set under a multi-year IR framework that is anticipated to end in 2012. The structure and fundamental parameters of the IR framework was approved by the OEB on January 17,

2008, with the associated annual rate changes implemented on April 1, 2008. Key elements of the framework include:

- Allowance for inflationary rate increases, offset by a productivity factor of 1.82% that is fixed for the duration of the five-year framework.
- Allowance for additional rate increases in the small-volume customer classes to reflect the decline in average use per customer. A new deferral account was also established to capture the variance between forecast and actual use per customer declines
- A $1 per month increase in the fixed monthly customer charge for small-volume customers for each year of the five-year term.
- Continued pass-through of gas commodity, upstream transportation and demand side management costs.
- An allowance for unexpected cost changes that are outside of management's control.
- An earnings sharing mechanism between the Company and its ratepayers, wherein if, in any calendar year, the Company's actual utility ROE is greater than 200 basis points over the allowed ROE, excess earnings will be shared 50/50 between Union and its customers.
- Union's 2008 ROE of 8.54% will remain unchanged throughout the IR period and the equity component also remains at 36%.
- The current Gas Cost Deferral Accounts, Storage and Other Deferral Accounts remain in place.

The settlement also stated that, in the event of a 300 basis point or greater variance in weather-normalized earnings above or below the allowed ROE, Union must file an application to review the IR plan.

Subsequently, when Union's normalized earnings for 2008 exceeded the 300 basis point limit, the company applied to the OEB for a review of the IR framework. Following this review, in June 2009, the OEB approved the agreement that Union had reached with stakeholders to replace the provision for mandatory reviews of the IR framework with a 90/10 cost-sharing mechanism (in favour of customers).

Gas Storage

A portion of Union's storage business is outside of regulation but the majority of Union's storage rates are regulated. On November 7, 2006, the OEB issued the decision that it would not regulate the price of storage services to customers outside Union's franchise area or of new storage services to customers within the franchise area. However, existing customers within the Company's franchise area continue to be charged at cost-based rates. The Storage Forebearance Decision also requires that Union share long-term storage margins with ratepayers over a four-year phase-out period that started in 2007.

Given Union's large storage capacity and current strong gas fundamentals, DBRS views the unregulated storage segment of its business as potentially positive for the Company as it allows Union to earn more profit from customers outside its franchise area and new customers within its franchise area. This upside is somewhat tempered by the potential incremental increase in risk profile and earnings volatility should the proportion of revenue from the unregulated segment develop to comprise a significant portion of the Company's overall earnings. Presently, the unregulated portion of Union's storage business comprises approximately one-third of its storage capacity and as such, DBRS does not view the unregulated earnings as materially impactful to the Company's overall earnings at this time.

Union Gas Limited

Report Date:
January 31, 2011

Earnings and Outlook

Income Statement *(C$ MM)*	**LTM**	**FYE Dec. 31st**				
	Sept. 30/10	**2009**	**2008**	**2007**	**2006**	**2005**
Gas Distribution Revenue (net)	678	658	675	655	606	639
Storage and Transportation Revenues	301	299	244	215	191	172
Ancillary Revenue	34	36	34	37	33	36
Operating Revenue	1,013	993	953	907	830	847
Total operating expenses	634	608	587	567	536	521
EBITDA	577	580	552	514	457	482
EBIT	379	385	366	340	294	326
Net Interest Expense	158	160	148	152	155	156
Income Taxes	41	48	41	48	37	50
Net Income (before extra. & pref divs)	180	177	177	140	102	120
Extraordinary Items gain/(loss)	0	2	(3)	5	2	1
Preferred Dividends	2	2	5	5	5	5
Net Income Available to Common	178	173	169	140	99	116
EBIT Margin (net of Cost of Gas)	37.4%	38.8%	38.4%	37.5%	35.4%	38.5%
Return on Common Equity	13.2%	13.4%	13.8%	11.6%	9.1%	10.9%

Summary

The company's earnings have demonstrably improved for the last 12 months (LTM) to September 30, 2010 vis-à-vis fiscal 2007 due primarily to increased revenues related to the expansion of storage and transmission capacity. Higher depreciation and operating costs primarily related to higher employee benefits associated with higher amortization of pension plan asset market value losses offset revenue gains.

Due to the seasonality of the Company's business, weather continues to play a significant role in its earnings. Since a large portion of the natural gas distributed to the residential and commercial market is used for space heating and is charged using volume-based rates, differences from normal weather patterns have a significant impact on the consumption of gas and the Company's financial profile. This was illustrated in 2006, when warmer-than-normal weather affected the Company's earnings.

The Company had historically experienced strong new customer growth due to high levels of construction activities which have moderated over the past few years. Approximately two-thirds of total revenues are generated from the Company's residential and commercial gas distribution customers, so variances in weather can have a significant impact on operating results. However, a significant portion of revenue derived from these customer classes are fixed demand charges.

Contribution to overall earnings from the Company's storage and transportation operations has also increased in recent years. Approximately 95% of storage and transportation revenues are generated by fixed demand charges under contracts with terms of up to 25 years and average outstanding terms of eight years.

Interest expense has increased modestly, attributable to increased levels of total debt as a result of corresponding higher growth capital expenditures in recent years.

Outlook

DBRS anticipates that earnings from Union's gas distribution segment will remain relatively stable in the near- to medium-term. New customer growth in the residential segment is expected to remain slow in 2011 and 2012, and a reduction in distribution throughput is expected as a result of ongoing energy conservation programs, including the Company's Demand Side Management (DSM) initiative, declining normalized use per customer and a general trend towards warmer weather.

Earnings from Union's storage and transportation operations should continue to increase as a result of increased throughput from the pipeline between Dawn and Trafalgar that was placed into service in late 2007/early 2008, and the pipeline expansion that is intended to support a gas-fired power plant near Sarnia. The addition of third-party gas-fired electric generating capacity within Union's service area is also anticipated to provide additional storage opportunities.

Union Gas Limited

Report Date:
January 31, 2011

Financial Profile

Cash Flow Statement *(C$ MM)*	LTM			FYE Dec. 31st		
	Sept. 30/10	2009	2008	2007	2006	2005
Net Income (before extras. & after prefs.)	178	175	172	135	97	115
Depreciation & Amortization	197	195	187	176	165	158
Non-Cash Charges & Deferred Income Taxes	21	(55)	13	12	(91)	20
Cash Flow From Operations	396	315	372	323	171	293
Dividends to Parent	(166)	(50)	(120)	(36)	(49)	(115)
Capital Expenditures	(187)	(247)	(404)	(373)	(340)	(231)
Free Cash Flow Before W/C	43	18	(152)	(86)	(218)	(53)
Change in Working Capital	(253)	327	(218)	(29)	273	(49)
Net Free Cash Flow	(210)	345	(370)	(115)	55	(102)
Acquisitions/Divestitures	0	0	0	(7)	0	0
Other	0	0	0	0	0	0
Cash Flow before Financing	(210)	345	(370)	(122)	55	(102)
Net Change in Debt Financing	179	(311)	362	13	53	98
Net Change in Preferred Equity Financing	0	0	0	0	0	0
Net Change in Common Equity Financing & Other	0	0	0	0	(1)	4
Net Change in Cash	(31)	34	(8)	(109)	107	0

Key Ratios *(C$ MM)*	LTM			FYE Dec. 31st		
	Sept. 30/10	2009	2008	2007	2006	2005
Total Debt	2,388	2,245	2,555	2,195	2,192	2,140
Debt/Capital	61.3%	61.1%	64.3%	61.7%	63.6%	64.0%
EBIT/Interest Expense	2.40x	2.41x	2.47x	2.24x	1.90x	2.09x
Cash Flow/Total Adj. Debt	16.6%	14.0%	14.6%	14.7%	7.8%	13.7%
Fixed-Charge Coverage	2.29x	2.30x	2.35x	2.13x	1.81x	1.99x

Summary

Overall, the Company's cash flow from operations has trended higher in recent years although it experienced a decline in 2009 as a result of higher income taxes. Despite the Company's rising cash flow from operations, however, higher working capital changes have resulted in free cash flow deficits. Union has financed these deficits through a combination of cash on hand and the issuance of short- and long-term debt. Dividends are primarily utilized to manage Union's capital structure at regulatory-approved levels.

While we note that there was an increase in the Company's cash flow-to-debt ratio at the end of the third quarter of 2010, this can be attributed primarily to deferred tax payments. Key credit metrics, such as cash flow-to-debt and coverage ratios, also remained strong for the most recent 12-month period and remain supportive of the current ratings.

Outlook

DBRS expects Union to be free cash flow negative this year, with de minimis deficits over the medium term due to capital expenditure related charges. Growth capital expenditure will be funded with a combination of short-term debt, long-term debt and dividend management in order to maintain the Company's credit metrics.

For 2010, cash flow from operations should be well in excess of capital expenditures which is anticipated to be approximately $257 million ($131 million of which had been spent by the end of Q3 2010), with 36% spent on transmission and storage projects, 53% on distribution projects and 11% on general equipment. DBRS anticipates that capital expenditures will remain on par with recent levels in the near- to medium-term as Union continues to focus on storage opportunities in order to grow its earnings and cash flow.

DBRS believes that the Company's capital projects will be financed in a manner that will ensure maintenance of a solid balance sheet and credit ratios appropriate for its rating category. Union continues to have strong access to the short- and long-term capital markets. DBRS expects that the parent will provide financial support to the Company in the form of equity injections and/or reduced dividends, if needed, to maintain its capital structure at the approved levels.

Long-Term Debt Maturities and Liquidity

Long-Term Debt Schedule*

(C$ MM)	Coupon	Maturity	2010	2009
Sinking Fund Debentures	11.6%	2010	37	65
Debentures	7.9%-11.5%	2014-2025	750	750
Medium-Term Note Debentures**	4.64%-7.2%	2011-2036	1,490	1,425
Total (including current portion)			2,277	2,240

Debt Maturity Schedule*

(C$ MM)		
2010	2%	37
2011	11%	250
2012	0%	0
2013	0%	0
Thereafter	87%	1,990
Total		**2,277**

Credit Facility*

(C$ MM)	Maturity Date	Committed	Drawn	Available
Five-year syndicated credit facility	2012	500	114	386
Total		500	114	386

*As at September 30, 2010.

**Union renewed its shelf prospectus to permit issue up to $500 MM of MTNs, expiry 2012.

DBRS views Union's liquidity as sufficient for its external funding requirements. Union's $500 million, five-year committed credit facility expires in July 2012 and is utilized to backstop the Company's $500 million commercial paper program. The facility contains a maximum 75% debt-to-capital covenant and includes a provision that requires the Company to repay all borrowings under the facility for a period of two days during the second quarter of each year.

Union, like its other gas utility peers, is generally subjected to seasonality as a part of its business and as a result, its short-term debt along with its gas inventory, typically peak in the first and fourth quarter of every year. However, since the Company recently experienced lower gas volatility, it also encountered decreased need for available liquidity to accommodate the volatility during injection season.

The Company's shelf prospectus was renewed and reduced to $500 million from $700 million in September 2010. Maturing in October 2012, the shelf contains a 75% maximum total debt-to-capitalization issuance covenant which will not restrict the Company from issuing debt to any significant extent as its current debt-to-capital ratio is ~60%. Any incremental debt is also subject to an Interest Coverage test of two times (calculated on earnings over any 12 consecutive months of the 23 calendar months immediately preceding a new debt issuance date). As at September 30, 2010, the Company was in compliance with all covenants.

Union Gas Limited

Report Date:
January 31, 2011

Union Gas Limited

Balance Sheet *(C$ MM)*

Assets	**As at Sept. 30/10**	**As at Dec. 31st 2009**	**2008**	**Liabilities & Equity**	**As at Sept. 30/10**	**As at Dec. 31st 2009**	**2008**
Cash	0	34	0	Short-Term Debt	118	39	321
Accounts Receivable	343	401	539	A/P & Accrued Charges	563	873	571
Inventories	255	224	228	LT Debt Due in One Year	287	222	29
Other	27	57	10	**Current Liabilities**	968	1,134	921
Current Assets	625	716	777	Long-Term Debt	1,978	1,979	2,200
Net fixed assets	4,308	4,303	3,827	Def'd Income Taxes & Others	926	890	300
Other	459	427	252	Debt Equiv. Pref.	5	5	5
				Preferred Equity	105	105	105
				Non-Controlling Interest	10	10	10
				Shareholders Equity	1,400	1,323	1,315
Total	5,392	5,446	4,856	**Total**	5,392	5,446	4,856

Ratio Analysis

	LTM Sept. 30/10	**2009**	**2008**	**FYE Dec. 31st 2007**	**2006**	**2005**
Liquidity Ratios						
Current Ratio	0.65x	0.63x	0.84x	0.58x	0.96x	1.02x
Cash Flow/Total Debt	16.6%	14.0%	14.6%	14.7%	7.8%	13.7%
Cash Flow/Capital Expenditures	2.12x	1.28x	0.92x	0.87x	0.50x	1.27x
Cash Flow-Dividends/Capital Expenditures (1)	1.23x	1.07x	0.62x	0.77x	0.36x	0.77x
Debt/Cap	61.3%	61.1%	64.3%	61.7%	63.6%	64.0%
Deemed Common Equity	36.0%	36.0%	36.0%	36.0%	35.0%	35.0%
Dividend Payout (1)	93.3%	28.6%	69.8%	26.7%	50.5%	100.0%
Debt/EBITDA	4.14x	3.87x	4.63x	4.27x	4.80x	4.44x
Coverage Ratios (2)						
EBIT/Interest Expense	2.40x	2.41x	2.47x	2.24x	1.90x	2.09x
EBITDA/Interest Expense	3.65x	3.63x	3.73x	3.38x	2.95x	3.09x
Fixed-Charge Coverage	2.29x	2.30x	2.35x	2.13x	1.81x	1.99x
Earnings Quality/Operating Efficiencies & Statistics						
Operating margin	37.4%	38.8%	38.4%	37.5%	35.4%	38.5%
Net margin (bef. extras., after preferred divs)	17.3%	17.3%	18.0%	14.9%	11.7%	13.6%
Return on avg. common equity	13.2%	13.4%	13.8%	11.6%	9.1%	10.9%
Approved ROE	8.54%	8.54%	8.54%	8.54%	9.63%	9.62%
Degree day deficiency – % normal	N/A	97.7%	97.8%	105.4%	115.9%	103.5%
Customer growth	N/A	1.2%	1.6%	1.7%	1.6%	2.0%

(1) Special dividends were paid to maintain capitalization within regulated limits in 2008 and 2005.
(2) Before capitalized interest, AFUDC, and debt amortizations.

Union Gas Limited

Report Date:
January 31, 2011

Rating

Debt	Rating	Rating Action	Trend
Unsecured Debentures/Medium Term Note Debentures	A	Confirmed	Stable
Commercial Paper	R-1 (low)	Confirmed	Stable
Cumulative Redeemable Preferred Shares	Pfd-2	Confirmed	Stable

Rating History

	Current	2009	2008	2007	2006	2005
Unsecured Debentures/Medium-Term Note Debentures	A	A	A	A	A	A
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)
Cumulative Redeemable Preferred Shares	Pfd-2	Pfd-2	Pfd-2	Pfd-2	Pfd-2	Pfd-2

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

UNION GAS LIMITED

Standard & Poor's Corporate Credit Rating

Standard & Poor's Financial Services LLC, provides independent financial information, analytical services, and credit ratings to the world's financial markets. For more information on Standard & Poor's, visit http://www.standardandpoors.com.

STANDARD
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SUMMARY ANALYSIS

Union Gas Ltd.

Credit Rating:
BBB+/Stable/A-2

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RatingsDirect
Publication Date
May 4, 2011

Rationale

The ratings on Union Gas Ltd., an Ontario-based natural gas distribution company, reflect Standard & Poor's Ratings Services' view of the consolidated credit profile of its ultimate parent, Spectra Energy Corp. (BBB+/Stable/—), and its strong business risk profile. Union Gas' monopoly-like market position, regulatory advantages, and stable cash flow generation underpin business fundamentals, in our opinion. Nevertheless, we believe that counterbalancing the ratings is the company's intermediate financial risk profile and softer key credit ratios.

Union Gas is the second-largest natural gas distribution utility in Canada, serving approximately 1.3 million customers in northern, southwestern, and eastern Ontario. The company has a very diverse customer base, in our view, with a large portion of residential customers that reduces volatility due to stable energy demands. In addition, it owns the largest gas storage facility in Canada, with a working storage capacity of 156 billion cubic feet (Dawn Storage, near Sarnia, Ont.) and operates a transmission system from Dawn to Oakville, Ont., which enhances business integration by providing customers value-added midstream services.

The company's strong business risk profile is a major factor underpinning the ratings and provides for stable overall operating performance. Union Gas' market-dominating gas distribution network and regulatory protection suppress competitive threats. A beneficial mechanism allows for a complete flow-through of commodity cost expense to customers by permitting the utility to adjust rates quarterly. The Ontario Energy Board (OEB) regulates the company's activities under a cost-of-service model where operating and interest costs are covered, and Union Gas is allowed to earn an allowed return on equity (ROE), which is key for rate-setting purposes. It is operating under an OEB-approved five-year incentive regulation agreement that began in 2008. The next period of cost-of-service rebasing is 2013. The current allowed ROE applies for the five-year incentive regulation period. This is a critical factor underlying the company's stable cash flow generation. While most revenue comes from regulated activities, Union Gas' unregulated storage business (one-third of total storage capacity) is expanding, which could introduce more earnings volatility and alter business risks. Nevertheless, we believe storage capability enhances operating flexibility and enables the company to manage its gas inventories, providing the benefit of supply security.

The ratings on Union Gas incorporate an updated review of its regulatory framework and how the regulation influences the actions of its parent company, Spectra Energy. We continue to equalize the ratings with those on the parent, which is consistent with our consolidated rating methodology and our usual treatment of regulated subsidiaries. Nevertheless, in our view, regulatory protection (through the OEB) of Union Gas is such that the ratings on it might not remain limited by the ratings on Spectra Energy in the event that the latter begins to deteriorate—which is consistent with our rating methodology that allows for rating separation of a utility and its parent in specific circumstances. We base this on the premise that under financial distress, Spectra Energy would have limited ability to withdraw cash or increase debt at Union Gas, protecting the utilities' financial risk profile.

Our view that regulatory protection is robust reflects the OEB's power and the provisions in the undertakings agreement. The regulator has what we believe are exceptional powers (from the Minister of Energy) to ensure that Union Gas continues to operate safely and efficiently, through a sound financial base. This is particularly important in the event that the parent company faces financial distress. The undertakings agreement between Spectra Energy and the OEB governs the financial and business activity of Union Gas to ensure operating sustainability. Some major provisions include a minimum equity level requirement (which can limit dividend payouts), quarterly capital structure forecasts, asset sale restrictions, and financial penalties for noncompliance.

In the case of regulated utilities, our methodology includes conditions under which we can rate a utility company higher than its parent. Other than robust regulatory protection, major considerations include the utility's strategic nature to the parent company and a higher stand-alone rating. Strategically, while Union Gas is a valuable asset to Spectra Energy and is a good strategic fit, we believe that it is not a critical component in the parent executing its broad overall business strategy. Furthermore, we believe that, given the OEB's legislated power and the critical nature of natural gas distribution services to consumers (particularly for heating, which is Union Gas' primary business), should Spectra Energy's credit profile deteriorate quickly, the OEB might initiate more comprehensive monitoring of Union Gas' financial position. This could lead to more stringent regulation on the company's operations through enhanced or amended measures in the undertakings agreement. Accordingly, rating separation is possible if Spectra's operational viability becomes questionable.

Influencing our view of Union Gas' significant financial risk profile are higher balance-sheet leverage and generally weaker financial metrics. The amount of equity on which the regulators allow Union Gas to earn an equity rate of return drives the capital structure. The company's ROE is lower than that of several U.S. peers, but is integral to earnings performance. Nevertheless, its stable cash flow generation allows it to withstand greater-than-normal financial leverage for its financial profile. Its EBIT continues to perform solidly with broad-based strength in gas distribution, storage, and transportation.

Liquidity

The short-term rating on Union Gas is 'A-2'. The company's overall liquidity position is adequate, in our view. It has robust and steady internally generated cash flow, which comfortably covers maintenance capex. The company also has a syndicated credit facility, which bolsters liquidity. This facility contains a covenant that limits Union Gas' debt-to-capitalization to 75%. Further supporting financial latitude is a laddered debt maturity schedule, which limits the potential for term and interest rate risk and access to capital markets (even in recent challenging market conditions). Nevertheless, the industry's capital-intensiveness will continue to place major demands on liquidity.

Outlook

The stable outlook reflects our view of Union Gas' dominant position in the Ontario natural gas distribution market and benefits of regulatory oversight that provide transparency, predictable operating results, and limitations of the parent company's influence. A strong business risk profile enables the utility to endure some cash flow volatility as it pursues nonregulated growth opportunities. We are unlikely to raise the rating during our outlook horizon amid limitations within its independent credit quality and equalization to the rating on its parent. Conversely, due to Union Gas' monopoly business position and regulatory insulation, a downgrade is also unlikely in the near term.

Union Gas Ltd.

Corporate Credit Rating
BBB+/Stable/A-2

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RatingsDirect Publication Date
Oct. 8, 2010

Major Rating Factors

Strengths:
- Dominant market position in gas distribution in its service area
- Provides essential service to consumers that is resistant to economic cycles
- Strategic ownership of natural gas storage and transmission assets enhances competitive position
- Regulated cash flows that bolsters stability

Weaknesses:
- High debt leverage associated with the company's regulated capital structure
- Allowed return on equity that is relatively low compared with that of U.S. peers
- Capital-intensive industry

Rationale

The ratings on Union Gas Ltd., an Ontario-based natural gas distribution company, reflect Standard & Poor's view of the consolidated credit profile of its ultimate parent, Spectra Energy Corp. (BBB+/Stable/—), and its strong business risk profile. The company's monopoly-like market position, regulatory advantages, and stable cash flow generation underpin business fundamentals. Nevertheless, we believe that counterbalancing the ratings is the company's intermediate financial risk profile and softer key credit ratios. Total long-term debt outstanding at Dec. 31, 2009 is approximately C$2.2 billion.

Union Gas is the second-largest natural gas distribution utility in Canada, serving approximately 1.3 million customers in northern, southwestern, and eastern Ontario. The company has a very diverse customer base, in our view, with a large portion of residential customers that reduces volatility due to stable energy demands. In addition, it owns the largest gas storage facility in Canada, with a working storage capacity of 156 billion cubic feet (Dawn Storage, near Sarnia, Ont.) and operates a transmission system from Dawn to Oakville, Ont., which enhances business integration by providing customers value added midstream services.

The company's strong business risk profile is a major factor underpinning the ratings and provides for stable overall operating performance. Union Gas' market-dominating gas distribution network and regulatory protection suppress competitive threats. A beneficial mechanism allows for a complete flow-through of commodity cost expense to customers by permitting the utility to adjust rates quarterly. The Ontario Energy Board (OEB) regulates the company's activities under a cost-of-service model where operating and interest costs are covered, and Union Gas is allowed to earn an allowed return on equity (8.54% for 2009), which is key for rate-setting purposes. It is operating under an OEB-approved five-year incentive regulation agreement that began in 2008. The next period of cost-of-service rebasing is 2013. The current allowed return on equity (ROE) applies for the five-year incentive regulation period. This is a critical factor underlying the company's stable cash flow generation. While most revenue comes from regulated activities, Union Gas' unregulated storage business (one-third of total storage capacity) is expanding, which could introduce more earnings volatility and alter its business risk dynamics. Nevertheless, storage capability enhances operating flexibility and enables the company to manage its gas inventories, providing the benefit of supply security.

The ratings on Union Gas incorporate an updated review of its regulatory framework and how the regulation influences the actions of its parent company, Spectra Energy. We continue to equalize the ratings with those on the parent, which is consistent with our consolidated rating methodology and our usual treatment of regulated subsidiaries. Nevertheless, in our view, regulatory protection (through the OEB) of Union Gas is such that the ratings on it might not remain limited by the ratings on Spectra Energy in the event that the latter begins to deteriorate—which is consistent with our rating methodology that allows for rating separation of a utility company and its parent in specific circumstances. This is based on the premise that, in our opinion, under financial distress, Spectra Energy would have limited ability to withdraw cash or increase debt at Union Gas, protecting the utilities' financial risk profile.

Our view that regulatory protection is robust reflects the OEB's power and the provisions in the undertakings agreement. The regulator has what we view as exceptional powers (from the Minister of Energy) to ensure that Union Gas continues to operate safely and efficiently, through a sound financial base. This is particularly important in the event that the parent company faces financial distress. The undertakings agreement between Spectra Energy and the OEB governs the financial and business activity of Union Gas to ensure operating sustainability. Some major provisions include a minimum equity level requirement (which can limit dividend payouts), quarterly capital structure forecasts, asset sale restrictions, and financial penalties for noncompliance.

In the case of regulated utilities, our methodology includes conditions under which we can rate a utility company higher than its parent. Other than robust regulatory protection, major considerations include the strategic nature of the utility to the parent company and a higher stand-alone rating. Strategically, while Union Gas is a valuable asset to Spectra Energy and is a good strategic fit, we believe that it is not a critical component in Spectra Energy executing its broad overall business strategy.

Furthermore, we believe that, given the OEB's legislated power and the critical nature of natural gas distribution services to consumers (particularly for heating, which is Union Gas' primary business), in the event that Spectra Energy's credit profile would deteriorate at an accelerated pace, the OEB might initiate more comprehensive monitoring of Union Gas' financial position. This could lead to more stringent regulation on the company's operations through enhanced or amended measures in the undertakings agreement. Accordingly, rating separation is possible if Spectra's operational viability becomes questionable.

Influencing our view of Union Gas' significant financial risk profile are higher balance-sheet leverage, with 65% debt-to-total capital (Standard & Poor's-adjusted) at Dec. 31, 2009; and generally weaker financial metrics. The amount of equity on which the regulators allow Union Gas to earn an equity rate of return drives the capital structure. The company's ROE is lower than that of several U.S. peers, but is integral to earnings performance. Nevertheless, its stable cash flow generation allows it to withstand greater-than-normal financial leverage for its financial profile. Union Gas' EBIT continues to perform solidly with broad-based strength in gas distribution, storage, and transportation, increasing to C$383 million in 2009 compared with C$369 million in 2008.

Short-term credit factors

The short-term rating on Union Gas is 'A-2'. The company's overall liquidity position is adequate, in our view. It has robust and steady internally generated cash flow, which comfortably covers maintenance capex. The company's C$500 million syndicated credit facility bolsters liquidity, and virtually all of it was available at Dec. 31, 2009. This facility contains a covenant that limits Union Gas' debt-to-capitalization to 75%. Financial latitude is further supported by a laddered debt maturity schedule, which limits the potential for term and interest rate risk and access to capital markets (even in recent challenging market conditions). Nevertheless, the industry's capital-intensiveness will continue to place major demands on liquidity.

Outlook

The stable outlook reflects our view of Union Gas' dominant position in the Ontario natural gas distribution market and benefits of regulatory oversight that provide transparency, predictable operating results, and limitations of the parent company's influence. A strong business risk profile enables Union Gas to endure some cash flow volatility as it pursues nonregulated growth opportunities. We are unlikely to raise the rating amid limitations within its independent credit quality and equalization to the rating on its parent. Conversely, due to Union Gas' monopoly business position and regulatory insulation, a downgrade is also unlikely in the near term.

Business Description

Union Gas engages primarily in natural gas distribution in Ontario, where it effectively has a monopoly position. The company also provides natural gas storage and transmission services, which provide diversification benefits. Union Gas is the second-largest natural gas distribution utility in Canada, serving approximately 1.3 million customers in northern, southwestern, and eastern Ontario. The company has what we view as a very diverse customer base, with a large portion of residential customers that generally have very stable energy demands. It also owns and operates a transmission system (from Dawn to Mississauga) and the largest gas storage facility in Canada, with a working storage capacity of 150 billion cubic feet.

Based on the OEB's January 2008 decision, the allowed ROE for 2008-2012 is 8.54%, and will stay there during the incentive regulation period. In our view, this is disadvantageous because the rate remains materially below that of the company's U.S. counterparts. Long-term bond yields substantially influence the allowed ROE.

Strong Business Risk Profile

Underpinning Union Gas' strong business risk profile is our view of the company's operational stability and regulatory protection. The OEB regulates all aspects of Union Gas' gas distribution business, including customer rates, system expansion, service adequacy, and public safety. Inelastic demand, particularly on the residential side, and few comparable energy substitutes support consistent business results, in our view. The company also owns an unregulated storage business, which provides services to other utilities and energy market participants.

While commodity price risk is associated with many energy related companies, Union Gas does not face this risk in its gas distribution business. Regulatory policy enables the company to fully pass through the cost of natural gas to its customers. Nevertheless, this could result in a timing mismatch and pressure on liquidity as Union Gas must apply to the OEB for rate increases. Regulation has somewhat shifted to a performance-based model, away from a cost-of-service methodology. We believe that this will likely lead to greater risks for management; but it also presents broadened opportunities to profit from efficient operations and business expansion. The OEB only allows a 36% equity component in the utility's capital structure and an 8.54% rate of return, which are both low compared with those of North American peers.

Markets face pressure

Union Gas serves most of Ontario, except for the Toronto and Ottawa metropolitan areas. Ontario's economy is experiencing a weak recovery because of less robust manufacturing activity and housing construction. Consequently, we expect that customer growth rates could slow in 2010 and 2011, despite increasing steadily at approximately 2% annually from 2006-2008. Distribution volume declined in 2009 amid warmer weather and a soft economy. Natural gas has long been available in Ontario, and the penetration rate for residential customers is high at approximately 71%. Natural gas continues to be the overwhelming choice for heating in new home construction. Industrial customers have switching capacity, but those volumes have lower margins than residential and commercial volumes. Natural gas-fired generation is sparse; most of the electricity in the province comes from nuclear and hydro facilities. With the province's emphasis on cleaner power sources, most new generation built in Ontario will likely be gas fired, which benefits the company.

Union Gas' overall financial performance is highly correlated to the performance of the gas distribution segment because it accounts for the vast majority of total earnings. Gas distribution's earnings have been very stable in recent years because incremental customer additions have offset to some extent the trend of reduced average consumption per user. Nevertheless, we expect customer growth rates to soften amid a tepid Ontario recovery. Revenue in the storage and transportation segment is less influential to Union Gas, but has experienced stronger growth. This business is primarily contract-based (95% is under contract) with an average term of five years, which reduces revenue volatility.

Competitive position

In our view, Union Gas does not face competitive threats in Ontario due to its dominant market position in gas distribution. Nevertheless, alternative fuels continue to provide competition and there is increasing emphasis on developing renewable energy sources. Electricity in particular is generally more expensive and natural gas is well-established as the fuel source of choice for residential space heating. Fuel oil can provide competition in periods of high gas prices, but residential and commercial customers who are unlikely to switch because of conversion costs drive the majority of the company's earnings.

We believe that the transmission system and storage assets are strategically relevant, and the Dawn hub is integral to managing the natural gas delivery from the west to markets in the U.S. Midwest and Northeast. The system's key competitive advantage is its large storage capacity, which enables efficient use of pipeline interconnections and is beneficial to U.S. customers, in our view. Several elements underpin Union Gas' competitive advantage in storage and transmission, including location, market liquidity, operating flexibility, and access to high-volume end users. Furthermore, because of its entrenched position in these areas and large capital costs that create barriers to entry, potential rivals would have a difficult time gaining market share.

Intermediate Financial Risk Profile

Accounting

Union Gas prepares its financial statements in accordance with Canadian generally accepted accounting principles and reports in Canadian dollars. The company's fiscal year-end is Dec. 31. We adjust key figures such as total debt, cash flow from operations, and EBITDA (for example, we add operating leases to debt); but these adjustments are modest, at less than 5% of total debt, for example, and are not major considerations in our analysis. The company enters derivative contracts only for hedging purposes. Overall, derivatives were not meaningful to our analysis because they are part of a regular program and used to manage risk, and are relatively small.

Profitability and cash flow

Amid supportive regulatory policies, Union Gas continues to generate robust and fairly predictable profits. EBIT increased in 2009 to C$385 million from C$366 million in 2008 (per company filings) amid stronger performance in the storage and transportation segment. Nevertheless, earnings can fluctuate at times due to changing weather conditions. For example, 2009 had warmer weather conditions, reducing natural gas demand. We note that OEB regulation does not protect against warmer-than-normal weather-reduced gas demand. Union Gas relies on rate increases and expanding its customer base to partially counter this adverse impact.

Leverage and ratios

Major credit ratios continue to be steady and indicative of the rating and overall financial flexibility is sound, in our view. Cash flow from operations can fluctuate due to working capital requirements, so we believe financial flexibility through credit facility availability and access to capital markets is vital. We expect Union Gas to use its C$500 million syndicated credit facility to fund major growth capex in 2010 and 2011 because internally generated cash flow will not be sufficient. Therefore, organic cash flow shortfalls are not an issue for us. A substantial portion of capex continues to go to storage and transmission assets, which we believe have encouraging growth prospects. Union Gas has C$250 million of debentures maturing in May 2011, which we believe it will refinance without difficulty.

Table 1

Union Gas Ltd.—Peer Comparison*

Industry Sector: Gas

	—Average of past three fiscal years—			
(Mil. C$)	***Union Gas Ltd.***	***Terasen Gas Inc.***	***Westcoast Energy Inc.***	***Gaz Metro Inc.***
Rating as of Oct. 8, 2010	***BBB+/Stable/A-2***	***A/Stable/—***	***BBB+/Stable/—***	***A-/Stable/—***
Revenues	2,070.7	1,541.5	3,670.0	2,123.4
Net income from continuing operations	166.7	85.4	394.0	39.8
Funds from operations (FFO)	351.8	168.1	831.1	383.2
Capital expenditures	338.8	86.7	617.2	138.0
Debt	2,320.8	1,631.7	4,931.7	1,867.5
Equity	1,266.7	846.9	3,504.6	800.9
Adjusted ratios				
Operating income (before D&A)/revenues (%)	27.6	20.2	34.4	19.9
EBIT interest coverage (x)	2.4	1.9	2.5	2.2
EBITDA interest coverage (x)	3.5	2.6	3.7	3.7
Return on capital (%)	10.4	9.0	9.7	9.4
FFO/debt (%)	15.2	10.3	16.9	20.5
Debt/EBITDA (x)	4.1	5.4	3.9	4.4

*Fully adjusted (including postretirement obligations). D&A—Depreciation and amortization.

Table 2

Union Gas Ltd.—Financial Summary*

Industry Sector: Gas

	—Fiscal year ended Dec. 31—				
(Mil. C$)	***2009***	***2008***	***2007***	***2006***	***2005***
Rating history	BBB+/Stable/A-2	BBB+/Stable/A-2	BBB+/Stable/A-2	BBB/Positive/—	BBB/Stable/—
Revenues	2,019.0	2,130.0	2,063.0	2,079.0	2,084.0
Net income from continuing operations	175.0	180.0	145.0	104.0	121.0
Funds from operations (FFO)	335.7	382.8	336.8	188.7	313.9
Capital expenditures	248.5	398.8	369.0	336.0	229.0
Cash and short-term investments	34.0	0.0	0.0	109.0	0.0
Debt	2,262.8	2,528.9	2,170.6	1,975.0	1,975.0
Preferred stock	105.0	105.0	105.0	105.0	105.0
Equity	1,247.7	1,284.4	1,268.1	1,126.6	1,057.4

Table 2

Union Gas Ltd.—Financial Summary* (cont.'d)

Debt and equity	3,510.5	3,813.2	3,438.7	3,101.5	3,032.4
Adjusted ratios					
EBIT interest coverage (x)	2.4	2.4	2.3	2.0	2.1
FFO interest coverage (x)	2.9	3.4	3.2	2.1	2.9
FFO/debt (%)	14.8	15.1	15.5	9.6	15.9
Discretionary cash flow/debt (%)	16.1	(14.0)	(4.7)	3.6	(4.3)
Net cash flow/capex (%)	115.0	65.9	80.2	40.1	84.7
Debt/debt and equity (%)	64.5	66.3	63.1	63.7	65.1
Return on common equity (%)	12.8	13.1	11.3	8.4	10.4
Common dividend payout ratio (unadjusted; %)	95.4	65.7	25.7	49.5	99.1

*Fully adjusted (including postretirement obligations).

Table 3

Reconciliation Of Union Gas Ltd. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. C$)* (cont.'d)

—Fiscal year ended Dec. 31, 2009—

Union Gas Ltd. reported amounts	***Debt***	***Shareholders' equity***	***Operating income (before D&A)***	***Operating income (before D&A)***	***Operating income (after D&A)***	***Interest expense***	***Cash flow from operations***	***Cash flow from operations***	***Capital expenditures***
Reported	2,240.0	1,428.0	580.0	580.0	385.0	160.0	642.0	642.0	247.0
Standard & Poor's adjustments									
Operating leases	23.1	N/A	5.5	1.5	1.5	1.5	4.0	4.0	5.5
Postretirement benefit obligations	135.3	(190.3)	16.0	16.0	16.0	1.0	23.5	23.5	N/A
Capitalized interest	N/A	N/A	N/A	N/A	N/A	4.0	(4.0)	(4.0)	(4.0)
Asset retirement obligations	72.4	N/A	4.0	4.0	4.0	4.0	(2.7)	(2.7)	N/A
Reclassification of nonoperating income (expenses)	N/A	N/A	N/A	N/A	(2.0)	N/A	N/A	N/A	N/A
Reclassification of working-capital cash flow changes	N/A	N/A	N/A	N/A	N/A	N/A	N/A	(327.0)	N/A
Minority interests	N/A	10.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Other	(208.0)	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total adjustments	22.8	(180.3)	25.5	21.5	19.5	10.5	20.7	(306.3)	1.5
Standard & Poor's adjusted amounts	***Debt***	***Equity***	***Operating income (before D&A)***	***EBITDA***	***EBIT***	***Interest expense***	***Cash flow from operations***	***Funds from operations***	***Capital expenditures***

Table 3

Reconciliation Of Union Gas Ltd. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. C$)* (cont.'d)

	—Fiscal year ended Dec. 31, 2009—								
Union Gas Ltd. reported amounts	*Debt*	*Shareholders' equity*	*Operating income (before D&A)*	*Operating income (before D&A)*	*Operating income (after D&A)*	*Interest expense*	*Cash flow from operations*	*Cash flow from operations*	*Capital expenditures*
Adjusted	2,262.8	1,247.7	605.5	601.5	404.5	170.5	662.7	335.7	248.5

*Union Gas Ltd. reported amounts shown are taken from the company's financial statements but might include adjustments made by data providers or reclassifications made by Standard & Poor's analysts. Please note that two reported amounts (operating income before D&A and cash flow from operations) are used to derive more than one Standard & Poor's-adjusted amount (operating income before D&A and EBITDA, and cash flow from operations and funds from operations, respectively). Consequently, the first section in some tables may feature duplicate descriptions and amounts. D&A—Depreciation and amortization. N/A—Not applicable.

Ratings Detail (As Of 08-Oct-2010)*

Union Gas Ltd.	
Corporate Credit Rating	BBB+/Stable/A-2
Commercial Paper	
Local Currency	A-2
Canadian National Scale Commercial Paper Rating	A-1(LOW)
Preferred Stock (5 Issues)	BBB-
Canadian Preferred Stock Rating (5 Issues)	P-2(Low)
Senior Unsecured (14 Issues)	BBB+
Corporate Credit Ratings History	
02-Jan-2007	BBB+/Stable/A-2
13-Sep-2006	BBB/Positive/--
29-Jun-2006	BBB/Developing/--
25-May-2006	BBB/Positive/--
Business Risk Profile	Strong
Financial Risk Profile	Significant
Related Entities	
Spectra Energy Capital LLC	
Issuer Credit Rating	BBB+/Stable/A-2
Senior Unsecured (8 Issues)	BBB
Spectra Energy Corp	
Issuer Credit Rating	BBB+/Stable/--
Senior Unsecured (4 Issues)	BBB
Texas Eastern Transmission LP	
Issuer Credit Rating	BBB+/Stable/--
Senior Unsecured (4 Issues)	BBB+
Westcoast Energy Inc.	
Issuer Credit Rating	BBB+/Stable/--
Commercial Paper	

Canadian National Scale Commercial Paper Rating	A-1(LOW)
Preferred Stock (3 Issues)	BBB-
Canadian Preferred Stock Rating (3 Issues)	P-2(Low)
Senior Unsecured (13 Issues)	BBB+

*Unless otherwise noted, all ratings in this report are global scale ratings. Standard & Poor's credit ratings on the global scale are comparable across countries. Standard & Poor's credit ratings on a national scale are relative to obligors or obligations within that specific country.

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UNION GAS LIMITED

Prospectuses, Information Circulars for Most Recent Financing

- 4.88% $300,000,000 MTN Debentures, issued June 21, 2011, due June 21, 2041
- 5.20% $250,000,000 MTN Debentures, issued July 23, 2010, due July 23, 2040
- 6.05% $300,000,000 MTN Debentures, issued September 2, 2008, due September 2, 2038
- 5.35% $200,000,000 MTN Debentures, issued April 28, 2008, due April 27, 2018
- 4.85% $125,000,000 MTN Debentures, issued November 23, 2006, due April 25, 2022
- 5.46% $165,000,000 MTN Debentures, issued September 11, 2006, due September 11, 2036

The previous Medium-Term Note Disclosures were issued on September 21, 2005.

Information on this was filed at EB-2005-0520, Exhibit A3, Tab 7.

This pricing supplement, together with the short form base shelf prospectus to which it relates, as amended or supplemented, and each document incorporated or deemed to be incorporated by reference into the short form base shelf prospectus, as amended or supplemented, constitutes a public offering of these securities only in those jurisdictions where they may be lawfully offered for sale and therein only by persons permitted to sell such securities. No securities regulatory authority has expressed an opinion about these securities and it is an offence to claim otherwise.

Pricing Supplement No. 1

Dated: June 16, 2011

To a Short Form Base Shelf Prospectus of Union Gas Limited dated September 10, 2010

UNION GAS LIMITED

4.88% MTN DEBENTURES, SERIES 9

(Unsecured)

Terms of the Medium Term Note Debentures (the "MTN Debentures") offered under this Pricing Supplement:

Amount and Currency of Issue:	CDN$300,000,000
Settlement Date:	June 21, 2011
Maturity Date:	June 21, 2041
Issue Price:	CDN$99.875
Commission:	0.50% of principal amount (Total Commission CDN$1,500,000)
Net Proceeds to the Issuer:	CDN$298,125,000
Interest Rate:	4.88 % per annum, payable semi-annually
Interest Payment Dates:	June 21 and December 21 commencing December 21, 2011
Form of Issuance:	To be issued in the form of a fully registered global debenture in the name of CDS & Co., as nominee of The Canadian Depository for Securities Limited. The MTN Debentures will be issued under the Trust Indenture dated as of August 1, 1968 between Union Gas Limited (the "Company") and The Royal Trust Company of Canada, as supplemented and amended.
Use of Proceeds:	To refinance prior maturities and for general corporate purposes.
Redemption:	Prior to December 21, 2040, the MTN Debentures, Series 9 will be redeemable, at the Company's option, in whole at any time or in part from time to time, on not less than 30 days' prior notice, at the higher of the Canada Yield Price (as defined below) and par, together in each case with accrued and unpaid interest to the date fixed for redemption. On and after December 21, 2040, the MTN Debentures, Series 9 will be redeemable at the Company's option, in whole but not in part at par, together with accrued and unpaid interest to the date fixed for redemption. In cases of partial redemption, the MTN Debentures to be redeemed will be selected by the Trustee pro rata or in such other manner as it shall deem equitable. "Canada Yield Price" shall mean a price equal to the price of the MTN Debentures, Series 9 calculated to provide a yield to maturity, compounded semiannually and calculated in accordance with generally accepted financial practice, equal to the Government of Canada Yield plus 0.3675% on the

business day preceding the date of the resolution authorizing the redemption. "Government of Canada Yield" on any date shall mean the yield to maturity on such date, compounded semi-annually and calculated in accordance with generally accepted financial practice, which a non-callable Government of Canada bond would carry if issued, in Canadian dollars in Canada, at 100% of its principal amount on such date with a term to maturity equal to the remaining term to maturity of the MTN Debentures, Series 9. The Government of Canada Yield will be the average of the yields provided by two major Canadian investment dealers selected by the Company. If less than all of the outstanding MTN Debentures, Series 9 are to be redeemed, the MTN Debentures, Series 9 to be so redeemed will be selected by the Trustee pro rata or in such manner as it shall deem equitable.

Sinking Fund:	None
Purchase for Cancellation:	The Company may purchase the MTN Debentures in the market or by tender or by private contract at any time and at any price.
Selling Agents:	BMO Nesbitt Burns Inc. TD Securities Inc. CIBC World Markets Inc. Scotia Capital Inc.
CUSIP No.	90664Z AU4

The following documents, which have been filed with the various securities commissions or similar authorities in each of the provinces of Canada since the filing of the short form base shelf prospectus dated September 10, 2010 (the "Prospectus") relating to the offering of MTN Debentures of the Company are, in addition to this pricing supplement, specifically incorporated by reference into and form an integral part of the Prospectus:

(a) The annual information form of the company, dated March 16, 2011, for the financial year ended December 31, 2010;

(b) Consolidated annual financial statements of the Company for the years ended December 31, 2010 and 2009 and the auditors' report thereon;

(c) The management's discussion and analysis of financial condition and results of operations for the year ended December 31, 2010;

(d) The earnings coverage calculations for the year ended December 31, 2010;

(e) The unaudited consolidated comparative interim financial statements of the Corporation as at and for the three month period ended March 31, 2011 including management's discussion and analysis filed in connection with such interim financial statements; and

(f) The earnings coverage calculations for the period ended March 31, 2011.

Auditors' Consent

We have read pricing supplement No. 1 dated June 16, 2011 to a short from base shelf prospectus dated September 10, 2010 relating to the issuance of up to $300 million of Medium Term Note Debentures (unsecured) (collectively, the "Prospectus") of Union Gas Limited (the "Company"). We have complied with Canadian generally accepted standards for an auditor's involvement with offering documents.

We consent to the incorporation by reference in the above-mentioned short form base shelf prospectus of our report to the shareholders of the Company on the consolidated balance sheets of the Company as at December 31, 2010, and 2009; and the consolidated statements of income and comprehensive income, retained earnings and cash flows for each of the years in the two-year period ended December 31, 2010. Our report is dated March 16, 2011.

(signed) "Deloitte & Touche LLP"

Chartered Accountants
Licensed Public Accountants
London, Ontario

June 16, 2011

This pricing supplement, together with the short form base shelf prospectus to which it relates, as amended or supplemented, and each document incorporated or deemed to be incorporated by reference into the short form base shelf prospectus, as amended or supplemented, constitutes a public offering of these securities only in those jurisdictions where they may be lawfully offered for sale and therein only by persons permitted to sell such securities. No securities regulatory authority has expressed an opinion about these securities and it is an offence to claim otherwise.

Pricing Supplement No. 2

Dated: July 20, 2010

To a Short Form Base Shelf Prospectus of Union Gas Limited dated August 22, 2008

UNION GAS LIMITED

5.20% MTN DEBENTURES, SERIES 8

(Unsecured)

Terms of the Medium Term Note Debentures (the "MTN Debentures") offered under this Pricing Supplement:

Amount and Currency of Issue:	CDN $250,000,000
Settlement Date:	July 23, 2010
Maturity Date:	July 23, 2040
Issue Price:	CDN $99.518
Commission:	0.50% of principal amount (Total Commission CDN $1,250,000)
Net Proceeds to the Issuer:	CDN $247,545,000
Interest Rate:	5.20% per annum, payable semi-annually
Interest Payment Dates:	July 23 and January 23 commencing January 23, 2011 (with equal semi-annual payments of CDN $6,500,000)
Form of Issuance:	To be issued in the form of a fully registered global debenture in the name of CDS & Co., as nominee of CDS Clearing and Depository Services Inc. The MTN Debentures will be issued under the Trust Indenture dated as of August 1, 1968 between Union Gas Limited (the "Company") and The Royal Trust Company of Canada, as supplemented and amended.
Use of Proceeds:	For general corporate purposes.
Redemption:	The MTN Debentures, Series 8 will be redeemable, at the Company's option, in whole at any time or in part from time to time, on not less than 30 days' prior notice, at the higher of the Canada Yield Price (as defined below) and par, together with accrued and unpaid interest to the date fixed for redemption. "Canada Yield Price" shall mean a price equal to the price of the MTN Debentures, Series 8 calculated to provide a yield to maturity, compounded semiannually and calculated in accordance with generally accepted financial practice, equal to the Government of Canada Yield plus 0.37% on the business day preceding the date of the resolution authorizing the redemption. "Government of Canada Yield" on any date shall mean the yield to maturity on such date, compounded semi-annually and calculated in accordance with generally accepted financial practice, which a non-callable Government of Canada bond would carry if issued, in Canadian dollars in Canada, at 100% of its principal amount on such date with a term to maturity

	equal to the remaining term to maturity of the MTN Debentures, Series 8. The Government of Canada Yield will be the average of the yields provided by two major Canadian investment dealers selected by the Company. If less than all of the outstanding MTN Debentures, Series 8 are to be redeemed, the MTN Debentures, Series 8 to be so redeemed will be selected by the Trustee in such manner as it shall deem equitable.
Sinking Fund:	None
Purchase for Cancellation:	The Company may purchase the MTN Debentures in the market or by tender or by private contract at any time and at any price.
Selling Agents:	CIBC World Markets Inc. TD Securities Inc. BMO Nesbitt Burns Inc. Scotia Capital Inc.
CUSIP No.	90664Z AT7

The following documents, which have been filed with the various securities commissions or similar authorities in each of the provinces of Canada, are specifically incorporated by reference into and form an integral part of the short form base shelf prospectus dated August 22, 2008 relating to the offering of MTN Debentures of the Company:

(a) the Annual Information Form of the Company, dated March 17, 2010, for the financial year ended December 31, 2009;

(b) the consolidated comparative financial statements of the Company as at and for the year ended December 31, 2009 and the auditors' report thereon;

(c) the management's discussion and analysis of financial condition and results of operations as at and for the year ended December 31, 2009;

(d) the unaudited consolidated comparative interim financial statements of the Company as at and for the three month period ended March 31, 2010, including management's discussion and analysis filed in connection with such interim financial statements;

(e) the earnings coverage calculations for the year ended December 31, 2009; and

(f) the earnings coverage calculations for the three months ended March 31, 2010.

Auditors' Consent

We have read pricing supplement No. 2 dated July 20, 2010 to a short from base shelf prospectus dated August 22, 2008 relating to the issuance of up to $250 million of Medium Term Note Debentures (unsecured) (collectively, the "Prospectus") of Union Gas Limited (the "Company"). We have complied with Canadian generally accepted standards for an auditor's involvement with offering documents.

We consent to the incorporation by reference in the above-mentioned short form base shelf prospectus of our report to the shareholders of the Company on the consolidated balance sheets of the Company as at December 31, 2009, and 2008; and the consolidated statements of income and comprehensive income, retained earnings and cash flows for each of the years in the two-year period ended December 31, 2009. Our report is dated March 17, 2010.

(signed) "Deloitte & Touche LLP"

Chartered Accountants
Licensed Public Accountants
London, Ontario

July 20, 2010

This pricing supplement, together with the short form base shelf prospectus to which it relates, as amended or supplemented, and each document incorporated or deemed to be incorporated by reference into the short form base shelf prospectus, as amended or supplemented, constitutes a public offering of these securities only in those jurisdictions where they may be lawfully offered for sale and therein only by persons permitted to sell such securities. No securities regulatory authority has expressed an opinion about these securities and it is an offence to claim otherwise.

Pricing Supplement No. 1

Dated: August 26, 2008

To a Short Form Base Shelf Prospectus of Union Gas Limited dated August 22, 2008

UNION GAS LIMITED

6.05% MTN DEBENTURES, SERIES 7

(Unsecured)

Terms of the Medium Term Note Debentures (the "MTN Debentures") offered under this Pricing Supplement:

Amount and Currency of Issue:	CDN$300,000,000
Settlement Date:	September 2, 2008
Maturity Date:	September 2, 2038
Issue Price:	CDN$99.808
Commission:	0.50 % of principal amount (Total Commission CDN$1,500,000)
Net Proceeds to the Issuer:	CDN$297,924,000
Interest Rate:	6.05% per annum, payable semi-annually
Interest Payment Dates:	March 2 and September 2 commencing March 2, 2009 (with equal semi-annual payments of CDN$9,075,000)
Form of Issuance:	To be issued in the form of a fully registered global debenture in the name of CDS & Co., as nominee of The Canadian Depository for Securities Limited. The MTN Debentures will be issued under the Trust Indenture dated as of August 1, 1968 between Union Gas Limited (the "Company") and The Royal Trust Company of Canada, as supplemented and amended.
Use of Proceeds:	To refinance prior maturities and for general corporate purposes.
Redemption:	The MTN Debentures, Series 7 will be redeemable, at the Company's option, in whole at any time or in part from time to time, on not less than 30 days' prior notice, at the higher of the Canada Yield Price (as defined below) and par, together with accrued and unpaid interest to the date fixed for redemption. "Canada Yield Price" shall mean a price equal to the price of the MTN Debentures, Series 7 calculated to provide a yield to maturity, compounded semiannually and calculated in accordance with generally accepted financial practice, equal to the Government of Canada Yield plus 0.50% on the business day preceding the date of the resolution authorizing the redemption. "Government of Canada Yield" on any date shall mean the yield to maturity on such date, compounded semi-annually and calculated in accordance with generally accepted financial practice, which a non-callable Government of Canada bond would carry if issued, in Canadian dollars in Canada, at 100% of its principal amount on such date with a term to maturity

	equal to the remaining term to maturity of the MTN Debentures, Series 7. The Government of Canada Yield will be the average of the yields provided by two major Canadian investment dealers selected by the Company. If less than all of the outstanding MTN Debentures, Series 7 are to be redeemed, the MTN Debentures, Series 7 to be so redeemed will be selected by the Trustee in such manner as it shall deem equitable.
Sinking Fund:	None
Purchase for Cancellation:	The Company may purchase the MTN Debentures in the market or by tender or by private contract at any time and at any price.
Selling Agents:	Scotia Capital Inc. BMO Nesbitt Burns Inc. CIBC World Markets Inc. TD Securities Inc.
CUSIP No.	90664Z AS9

The following documents, which have been filed with the various securities commissions or similar authorities in each of the provinces of Canada, are specifically incorporated by reference into and form an integral part of the short form base shelf prospectus dated August 22, 2008 relating to the offering of MTN Debentures of the Company:

(a) the Annual Information Form of the Company, dated March 20, 2008, for the financial year ended December 31, 2007;

(b) the consolidated comparative financial statements of the Company as at and for the year ended December 31, 2007 and the auditors' report thereon;

(c) the management's discussion and analysis of financial condition and results of operations as at and for the year ended December 31, 2007;

(d) the unaudited consolidated comparative interim financial statements of the Company as at and for the three and six month periods ended June 30, 2008, including management's discussion and analysis filed in connection with such interim financial statements; and

(e) the earnings coverage calculations for the year ended December 31, 2007

Auditors' Consent

We have read Pricing Supplement No. 1 dated August 26, 2008 of Union Gas Limited (the "Company") relating to the offering of $300,000,000 of Medium Term Note Debentures (unsecured) of the Company, to the short form base shelf prospectus dated August 22, 2008 qualifying the distribution of an aggregate principal amount of up to $700,000,000 Medium Term Notes (unsecured) of the Company. We have complied with Canadian generally accepted standards for an auditor's involvement with offering documents.

We consent to the incorporation by reference in the above-mentioned short form base shelf prospectus of our report to the shareholders of the Company on the consolidated balance sheets of the Company as at December 31, 2007 and 2006, and the consolidated statements of income and comprehensive income, retained earnings and cash flows for the years then ended. Our report is dated March 20, 2008.

(signed) "Deloitte & Touche LLP"

Chartered Accountants
Licensed Public Accountants
Windsor, Ontario

August 26, 2008

This pricing supplement, together with the short form base shelf prospectus to which it relates, as amended or supplemented, and each document incorporated or deemed to be incorporated by reference into the short form base shelf prospectus, as amended or supplemented, constitutes a public offering of these securities only in those jurisdictions where they may be lawfully offered for sale and therein only by persons permitted to sell such securities. No securities regulatory authority has expressed an opinion about these securities and it is an offence to claim otherwise.

Pricing Supplement No. 3

Dated: April 23, 2008

To a Short Form Base Shelf Prospectus and Prospectus Supplement of Union Gas Limited, each dated July 20, 2006

UNION GAS LIMITED

5.35% MTN DEBENTURES, SERIES 6

(Unsecured)

Terms of the Medium Term Note Debentures (the "MTN Debentures") offered under this Pricing Supplement:

Amount and Currency of Issue:	CDN$200,000,000
Settlement Date:	April 28, 2008
Maturity Date:	April 27, 2018
Issue Price:	CDN$99.87
Commission:	0.40% of principal amount (Total Commission CDN$800,000)
Net Proceeds to the Issuer:	CDN$198,940,000
Interest Rate:	5.35% per annum, payable semi-annually
Interest Payment Dates:	October 27 and April 27 commencing October 27, 2008 (first interest period runs from April 28, 2008 until October 27, 2008 with a payment of CDN$5,335,342.47; thereafter, the semi-annual interest payments will be CDN$5,350,000).
Form of Issuance:	To be issued in the form of a fully registered global debenture in the name of CDS & Co., as nominee of The Canadian Depository for Securities Limited. The MTN Debentures will be issued under the Trust Indenture dated as of August 1, 1968 between Union Gas Limited (the "Company") and The Royal Trust Company of Canada, as supplemented and amended.
Use of Proceeds:	To refinance prior maturities and for general corporate purposes.
Redemption:	The MTN Debentures, Series 6 will be redeemable, at the Company's option, in whole at any time or in part from time to time, on not less than 30 days' prior notice, at the higher of the Canada Yield Price (as defined below) and par, together with accrued and unpaid interest to the date fixed for redemption. "Canada Yield Price" shall mean a price equal to the price of the MTN Debentures, Series 6 calculated to provide a yield to maturity, compounded semiannually and calculated in accordance with generally accepted financial practice, equal to the Government of Canada Yield plus 0.39% on the business day preceding the date of the resolution authorizing the redemption. "Government of Canada Yield" on any date shall mean the yield to maturity on such date, compounded semi-annually and calculated in accordance with generally accepted financial practice, which a non-callable

	Government of Canada bond would carry if issued, in Canadian dollars in Canada, at 100% of its principal amount on such date with a term to maturity equal to the remaining term to maturity of the MTN Debentures, Series 6. The Government of Canada Yield will be the average of the yields provided by two major Canadian investment dealers selected by the Company. If less than all of the outstanding MTN Debentures, Series 6 are to be redeemed, the MTN Debentures, Series 6 to be so redeemed will be selected by the Trustee in such manner as it shall deem equitable.
Sinking Fund:	None
Purchase for Cancellation:	The Company may purchase the MTN Debentures in the market or by tender or by private contract at any time and at any price.
Selling Agents:	CIBC World Markets Inc. BMO Nesbitt Burns Inc. Scotia Capital Inc. TD Securities Inc.
CUSIP No.	90664ZAR1

The following documents, which have been filed with the various securities commissions or similar authorities in each of the provinces of Canada since the filing of the short form base shelf prospectus dated July 20, 2006 (the "Prospectus") and the prospectus supplement dated July 20, 2006 relating to the offering of MTN Debentures, are, in addition to the prospectus supplement and this pricing supplement, specifically incorporated by reference into and form an integral part of the Prospectus:

(a) The annual information form of the company, dated March 20, 2008, for the financial year ended December 31, 2007;

(b) Consolidated annual financial statements of the Company for the years ended December 31, 2007 and 2006 and the auditors' report thereon, including the management's discussion and analysis of financial condition and results of operations; and

(c) The earnings coverage calculations for the year ended December 31, 2007.

This pricing supplement, together with the short form base shelf prospectus to which it relates, as amended or supplemented, and each document incorporated or deemed to be incorporated by reference into the short form base shelf prospectus, as amended or supplemented, constitutes a public offering of these securities only in those jurisdictions where they may be lawfully offered for sale and therein only by persons permitted to sell such securities. No securities regulatory authority has expressed an opinion about these securities and it is an offence to claim otherwise.

Pricing Supplement No. 2

Dated: November 20, 2006

To a Short Form Base Shelf Prospectus and Prospectus Supplement of Union Gas Limited, each dated July 20, 2006

UNION GAS LIMITED

4.85% MTN DEBENTURES, SERIES 6

(Unsecured)

Terms of the Medium Term Note Debentures (the "MTN Debentures") offered under this Pricing Supplement:

Amount and Currency of Issue:	CDN$125,000,000
Settlement Date:	November 23, 2006
Maturity Date:	April 25, 2022
Issue Price:	CDN$99.81
Net Proceeds to the Issuer:	CDN$124,762,500
Interest Rate:	4.85% per annum, payable semi-annually
Interest Payment Dates:	April 25 and October 25 commencing April 25, 2007 (first interest period runs from November 23, 2006 until April 25, 2007 with a payment of $2,541,267.12; thereafter, the semi-annual interest payments will be $3,031,250.00).
Commission:	0.45%
Form of Issuance:	To be issued in the form of a fully registered global debenture in the name of CDS & Co., as nominee of The Canadian Depository for Securities Limited. The MTN Debentures will be issued under the Trust Indenture dated as of August 1, 1968 between Union Gas Limited (the "Company") and The Royal Trust Company of Canada, as supplemented and amended.
Use of Proceeds:	To refinance prior maturities and for general corporate purposes.
Redemption:	The MTN Debentures, Series 6 will be redeemable, at the Company's option, in whole at any time or in part from time to time, on not less than 30 days' prior notice, at the higher of the Canada Yield Price (as defined below) and par, together with accrued and unpaid interest to the date fixed for redemption. "Canada Yield Price" shall mean a price equal to the price of the MTN Debentures, Series 6 calculated to provide a yield to maturity, compounded semiannually and calculated in accordance with generally accepted financial practice, equal to the Government of Canada Yield plus 0.19% on the business day preceding the date of the resolution authorizing the redemption. "Government of Canada Yield" on any date shall mean the yield to maturity on such date, compounded semi-annually and calculated in

	accordance with generally accepted financial practice, which a non-callable Government of Canada bond would carry if issued, in Canadian dollars in Canada, at 100% of its principal amount on such date with a term to maturity equal to the remaining term to maturity of the MTN Debentures, Series 6. The Government of Canada Yield will be the average of the yields provided by two major Canadian investment dealers selected by the Company. If less than all of the outstanding MTN Debentures, Series 6 are to be redeemed, the MTN Debentures, Series 6 to be so redeemed will be selected by the Trustee in such manner as it shall deem equitable.
Sinking Fund:	None
Purchase for Cancellation:	The Company may purchase the MTN Debentures in the market or by tender or by private contract at any time and at any price.
Selling Agents:	TD Securities Inc. BMO Nesbitt Burns Inc. CIBC World Markets Inc. HSBC Securities (Canada) Inc. Scotia Capital Inc.
CUSIP No.	90664ZAQ3

The following documents, which have been filed with the various securities commissions or similar authorities in each of the provinces of Canada since the filing of the short form base shelf prospectus dated July 20, 2006 (the "Prospectus") and the prospectus supplement dated July 20, 2006 relating to the offering of MTN Debentures, are, in addition to the prospectus supplement and this pricing supplement, specifically incorporated by reference into and form an integral part of the Prospectus:

(a) the interim unaudited comparative financial statements of the Company for the nine-months ended September 30, 2006, including management's discussion and analysis filed in connection with such interim financial statements; and

(b) the earnings coverage calculations for the nine-months ended September 30, 2006.

This pricing supplement, together with the short form base shelf prospectus to which it relates, as amended or supplemented, and each document incorporated or deemed to be incorporated by reference into the short form base shelf prospectus, as amended or supplemented, constitutes a public offering of these securities only in those jurisdictions where they may be lawfully offered for sale and therein only by persons permitted to sell such securities. No securities regulatory authority has expressed an opinion about these securities and it is an offence to claim otherwise.

Pricing Supplement No. 1

Dated: September 6, 2006

To a Short Form Base Shelf Prospectus and Prospectus Supplement of Union Gas Limited, each dated July 20, 2006

UNION GAS LIMITED

5.46% MTN DEBENTURES, SERIES 6

(Unsecured)

Terms of the Medium Term Note Debentures (the "MTN Debentures") offered under this Pricing Supplement:

Amount and Currency of Issue:	CDN$165,000,000
Settlement Date:	September 11, 2006
Maturity Date:	September 11, 2036
Issue Price:	CDN$100.00
Net Proceeds to the Issuer:	CDN$164,175,000
Interest Rate:	5.46% per annum, payable semi-annually
Interest Payment Dates:	September 11 and March 11 commencing March 11, 2007 (first interest period runs from September 11, 2006 until March 11, 2007).
Commission:	0.50%
Form of Issuance:	To be issued in the form of a fully registered global debenture in the name of CDS & Co., as nominee of The Canadian Depository for Securities Limited. The MTN Debentures will be issued under the Trust Indenture dated as of August 1, 1968 between Union Gas Limited (the "Company") and The Royal Trust Company of Canada, as supplemented and amended.
Use of Proceeds:	To refinance prior maturities and for general corporate purposes.
Redemption:	The MTN Debentures, Series 6 will be redeemable, at the Company's option, in whole at any time or in part from time to time, on not less than 30 days' prior notice, at the higher of the Canada Yield Price (as defined below) and par, together with accrued and unpaid interest to the date fixed for redemption. "Canada Yield Price" shall mean a price equal to the price of the MTN Debentures, Series 6 calculated to provide a yield to maturity, compounded semiannually and calculated in accordance with generally accepted financial practice, equal to the Government of Canada Yield plus 0.29% on the business day preceding the date of the resolution authorizing the redemption. "Government of Canada Yield" on any date shall mean the yield to maturity on such date, compounded semi-annually and calculated in accordance with generally accepted financial practice, which a non-callable Government of Canada bond would carry if issued, in Canadian dollars in

	Canada, at 100% of its principal amount on such date with a term to maturity equal to the remaining term to maturity of the MTN Debentures, Series 6. The Government of Canada Yield will be the average of the yields provided by two major Canadian investment dealers selected by the Company. If less than all of the outstanding MTN Debentures, Series 6 are to be redeemed, the MTN Debentures, Series 6 to be so redeemed will be selected by the Trustee in such manner as it shall deem equitable.
Sinking Fund:	None
Purchase for Cancellation:	The Company may purchase the MTN Debentures in the market or by tender or by private contract at any time and at any price.
Selling Agents:	Scotia Capital Inc. TD Securities Inc. CIBC World Markets Inc. HSBC Securities (Canada) Inc. BMO Nesbitt Burns Inc.
CUSIP No.	90664ZAP5

The following documents, which have been filed with the various securities commissions or similar authorities in each of the provinces of Canada since the filing of the short form base shelf prospectus dated July 20, 2006 (the "Prospectus") and the prospectus supplement dated July 20, 2006 relating to the offering of MTN Debentures, are, in addition to the prospectus supplement and this pricing supplement, specifically incorporated by reference into and form an integral part of the Prospectus:

(a) the interim unaudited comparative financial statements of the Company for the six-months ended June 30, 2006, including management's discussion and analysis filed in connection with such interim financial statements; and

(b) the earnings coverage calculations for the six-months ended June 30, 2006.