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December 3, 2010

VIA RESS, EMAIL and COURIER

Ms Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, Suite 2700
Toronto, Ontario, M4P 1E4

Dear Ms Walli:

Re: Enbridge Gas Distribution Inc. ("Enbridge" of the "Company"))
2011 Rate Adjustment Application
Ontario Energy Board ("Board") File Number EB-2010-0146

In accordance with the Board's Decision and Order, dated November 25, 2010, wherein the Board approved the Settlement Agreement filed November 23, 2010, the Draft Rate Order ("DRO") was filed and circulated to all Intervenors on November 26, 2010, with the request that parties file their comments in response, if any, by December 2, 2010, which was the four day response period directed by the Board in its Decision and Order.

In response to the filing of the 2011 DRO, Enbridge received comments from Building Owners and Managers Association ("BOMA") regarding corrections in the Draft Rate Order.

The following corrections have been made to the 2011 DRO:

- page 70 of 164, the docket number was changed to EB-2010-0146; and
- page 114 of 164, the title has been changed to " For the 2011Fiscal Year (January 1, 2011 to December 31, 2011)"

The complete Draft Rate Order has been filed through the Board's Regulatory Electronic Submission System ("RESS") and will be available on the Enbridge website at www.enbridgegas.com/ratecase.

Two paper copies are being forwarded to the Board via courier.

Please contact the undersigned if you have any questions.

Yours truly,

Bonnie Jean Adams

Bonnie Jean Adams
Regulatory Coordinator, Regulatory Affairs

cc: Mr. F. Cass, Aird & Berlis LLP (via email)
All Interested Parties EB-2009-0172 (via email)

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Robert Bourke
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November 26, 2010

VIA COURIER

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Ms. Walli:

Re: Enbridge Gas Distribution Inc. ("EGD" or the "Company")
Draft Final Rate Order - 2011 Rate Proceeding EB-2010-0146

Attached please find the Company's draft materials for inclusion in the Board's Final Rate Order for 2011 rates, which have been prepared subsequent to the Approval by the Ontario Energy Board (the "Board") of the Settlement Agreement on November 25, 2010, in EGD's 2011 Rate Proceeding, docket EB-2010-0146.

The materials for inclusion in the Board's Final Rate Order for 2010 rates include the following:

- Appendix "A" – Financial Statement applicable for the 2011 Test Year as per EB-2010-0146, Exhibit B, Tab 1, Schedule 2, page 1;
- Appendix "B" – Rate Handbook reflecting final 2011 rates as per the Settlement Agreement which is filed at Appendix F;
- Supporting documentation for Appendix B.
- Appendix "C" – Not Used[1].
- Appendix "D" - Accounting treatment for all 2011 Deferral and Variance Accounts.
- Appendix "E" - Final Issues List.
- Appendix "F" - Settlement Agreement.

The customer rate notices will be filed as part of the January 1, 2011 QRAM application under docket EB-2010-0347 which will be filed on or before December 10, 2010.

Proposed Time Table: The draft materials for the Board's Final Rate Order have been circulated for review and approval by all active participants in the settlement conference.

The Company is respectfully requesting that the Board approve and issue the Final Rate Order on or before December 10, 2010 in order to maintain the timetable for the filing and approval the January 2011 QRAM and the implementation of final 2011 rates resulting from the EB-2010-0146 rate proceeding as part of the January 2011 QRAM.

With the filing of these Draft Rate Order materials, and incorporating the Board's timetable as indicated in its EB-2010-0146 Decision and Order dated November 25, 2010, the Company respectfully requests comments from parties no later than Thursday December 2, 2010 in order to allow for Company reply to any comments received by Monday December 6, 2010.

Thank you for this consideration.

Yours truly,

Robert Bourke
Manager Regulatory Proceedings

Encl.

cc: Mr. F. D. Cass, Aird & Berlis (via courier)
EB-2010-0146 Interested Parties (via email only)

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[1] Appendix C would normally contain the material in support of the derivation for Rider E. As there is no Rider E associated with this rate change, the appendix is shown only as a place given that other material has been prepared in advance.

APPENDIX “A”

Financial Statements

2011 REVENUE PER CUSTOMER CAP, DISTRIBUTION AND TOTAL REVENUE DETERMINATION

Row		Col. 1 2011
1.	2010 Total Approved Revenue	2,434.3
2.	Gas Costs to operations (at Oct. 1, 2009 ref. price)	1,453.5
3.	2010 Approved Distribution Revenue	980.8
4.	2010 Gas in storage related carrying costs (at Oct. 1, 2009 ref. price)	(36.7)
5.	DSM 2010 amount	(26.7)
6.	CIS / Cust. Care 2010 amount	(95.7)
7.	Power generation projects 2010 amount	(3.6)
8.	Distribution Revenue Sub-total	818.1
9.	Ratepayer 50% share of 2011 incremental tax amounts	(5.3)
10.	Distribution Revenue base (subject to the escalation formula, $millions)	812.8
11.	Average Number of Customers (Beginning)	1,931,528
12.	Distribution Revenue per Customer 2011 (Beginning)	$ 420.81
13.	GDP IPI FDD	0.72%
14.	Inflation Coefficient (allowed % of GDP IPI FDD)	50.00%
15.	Escalation Factor, 100 plus (GDP IPI FDD multiplied by the inflation coeff.)	100.36%
16.	Distribution Revenue per Customer 2011 (Ending)	$ 422.32
17.	Average Number of Customers (Ending)	1,965,537
18.	Distribution Revenue (resulting from the escalation formula, $millions)	830.09
	Y-Factors	
19.	2011 Gas in storage related carrying costs (at October 1, 2010 ref. price)	30.90
20.	2011 DSM Y-factor amount	26.70
21.	CIS / Customer Care 2011 approved amount	97.40
22.	Power generation projects 2011 amount	3.50
23.	Total 2011 Y-Factors	158.50
24.	Total 2011 Distribution Revenues	988.59
25.	2011 Gas Costs to operations (at October 1, 2010 ref. price)	1,416.30
26.	2011 Total Revenue	2,404.89

APPENDIX “B”

Rate Handbook

RATE HANDBOOK

ENBRIDGE GAS DISTRIBUTION

HANDBOOK OF RATES AND DISTRIBUTION SERVICES

INDEX

Part I

GLOSSARY OF TERMS

In this Handbook of Rates and Distribution Services, each term set out below shall have the meaning set out opposite it:

Annual Turnover Volume ("ATV"): The sum of the contracted volumes injected into and withdrawn from storage by an applicant within a contract year.

Annual Volume Deficiency: The difference between the Minimum Annual Volume and the volume actually taken in a contract year, if such volume is less than the Minimum Annual Volume.

Applicant: The party who makes application to the Company for one or more of the services of the Company and such term includes any party receiving one or more of the services of the Company.

Authorized Volume: In regards to Sales Service Agreements, the Contract Demand.

In regards to Bundled Transportation Service arrangements, the Contract Demand (CD) less the amount by which the Applicant's Mean Daily Volume (MDV) exceeds the Daily Delivered Volume (Delivery) and less the volume by which the Applicant has been ordered to curtail or discontinue the use of gas (Curtailment Volume) or otherwise represented as:

CD – (MDV – Delivery) – Curtailment Volume

Back-stopping: A service whereby alternative supplies of gas may be available in the event that an Applicant's supply of gas is not available for delivery to the Company.

Banked Gas Account: A record of the amount of gas delivered by the Applicant to the Company in respect of a Terminal Location (credits) and of volume of gas taken by the Applicant at the Terminal Location (debits)

Billing Contract Demand: Applicable only to new customers who take Dedicated Service under Rate 125. The Company and the Applicant shall determine a Billing Contract Demand which would result in annual revenues over the term of the contract that would enable the Company to recover the invested capital, return on capital, and O&M costs of the Dedicated Service in accordance with its system expansion policies.

Billing Month: A period of approximately thirty (30) days following which the Company renders a bill to an applicant. The billing month is determined by the Company's monthly Reading and Billing Schedule. With respect to rate 135 LVDC's, there are eight summer months and four winter months.

Board: Ontario Energy Board. (OEB)

Bundled Service: A service in which the demand for natural gas at a Terminal Location is met by the Company utilizing Load balancing resources.

Buy/Sell Arrangement: An arrangement, the terms of which are provided for in one or more agreements to which one or more of an end user of gas (being a party that buys from the Company gas delivered to a Terminal Location), an affiliate of an end user and a marketer, broker or agent of an end user is a party and the Company is a party, and pursuant to which the Company agrees to buy from the end user or its affiliate a supply of gas and to sell to the end user gas delivered to a Terminal Location served from the gas distribution network. The Company will not enter into any new buy/sell agreement after April 1, 1999.

Buy/Sell Price: The Price per cubic meter which the Company would pay for gas purchased pursuant to a Buy/Sell Arrangement in which the purchase takes place in Ontario.

Commodity Charge: A charge per unit volume of gas actually taken by the Applicant, as distinguished from a demand charge which is based on the maximum daily volume an Applicant has the right to take.

Company: Enbridge Gas Distribution Inc.

Contract Demand: A contractually specified volume of gas applicable to service under a particular Rate Schedule for each Terminal Location which is the maximum volume of gas the Company is required to deliver on a daily basis under a Large Volume Distribution Contract.

Cubic Metre ("m^3"): That volume of gas which at a temperature of 15 degrees Celsius and at an absolute pressure of 101.325 kilopascals ("kPa") occupies one cubic metre. "10^3m^3" means 1,000 cubic metres.

Curtailment: An interruption in an Applicant's gas supply at a Terminal Location resulting from compliance with a request or an order by the Company to discontinue or curtail the use of gas.

Curtailment Credit: A credit available to interruptible customers to recognize the benefits they provide to the system during the winter months.

Curtailment Delivered Supply (CDS): An additional volume of gas, in excess of the Applicant's Mean Daily Volume and determined by mutual agreement between the Applicant and the Company, which is Nominated and delivered by or on behalf of the Applicant to a point of interconnection with the Company's distribution system on a day of Curtailment.

Customer Charge: A monthly fixed charge that reflects being connected to the gas distribution system.

Daily Consumption VS Gas Quantity: The volume of natural gas taken on a day at a Terminal Location as measured by daily metering equipment or, where the Company does not own and maintain daily metering equipment at a Terminal Location, the volume of gas taken within a billing period divided by the number of days in the billing period.

Daily Delivered Volume: The volume of gas accepted by the Company as having been delivered by an Applicant to the Company on a day.

Dedicated Service: An Unbundled Service provided through a gas distribution pipeline that is initially constructed to serve a single customer, and for which the volume of gas is measured through a billing meter that is directly connected to a third party transporter or other third party facility, when service commences.

Delivery Charge: A component of the Rate Schedule through which the Company recovers its operating costs.

Demand Charge: A fixed monthly charge which is applied to the Contract Demand specified in a Service Contract.

Demand Overrun: The amount of gas taken at a Terminal Location exceeding the Contract Demand.

Direct Purchase: Natural gas supply purchase arrangements transacted directly between the Applicant and one or more parties, including the Company.

Disconnect and Reconnect Charges: The charges levied by the Company for disconnecting or reconnecting an Applicant from or to the Company's distribution system.

Diversion: Delivery of gas on a day to a delivery point different from the normal delivery point specified in a Service Contract.

Firm Service: A service for a continuous delivery of gas without curtailment, except under extraordinary circumstances.

Firm Transportation ("FT"): Firm Transportation service offered by upstream pipelines to move gas from a receipt point to a delivery point, as defined by the pipeline.

Force Majeure: Any cause not reasonably within the control of the Company and which the Company cannot prevent or overcome with reasonable due diligence, including:

(a) physical events such as an act of God, landslide, earthquake, storm or storm warning such as a hurricane which results in evacuation of an affected area, flood, washout, explosion, breakage or accident to machinery or equipment or lines of pipe used to transport gas, the necessity for making repairs to or alterations of such machinery or equipment or lines of pipe or inability to obtain materials, supplies (including a supply of services) or permits required by the Company to provide service;

(b) interruption and/or curtailment of firm transportation by a gas transporter for the Company;

(c) acts of others such as strike, lockout or other industrial disturbance, civil disturbance, blockade, act of a public enemy, terrorism, riot, sabotage, insurrections or war, as well as physical damage resulting from the negligence of others;

(d) in relation to Load Balancing, failure or malfunction of any storage equipment or facilities of the Company; and

(e) governmental actions, such as necessity for compliance with any applicable laws.

Gas: Natural Gas.

Gas Delivery Agreement: A written agreement pursuant to which the Company agrees to transport gas on the Applicant's behalf to a specified Terminal Location.

Gas Distribution Network: The physical facilities owned by the Company and utilized to contain, move and measure natural gas.

Gas Sale Contract: A written agreement pursuant to which the Company agrees to supply and deliver gas to a specified Terminal Location.

Gas Supply Charge: A charge for the gas commodity purchased by the applicant.

Gas Supply Load Balancing Charge: A charge in the Rate Schedules where the Company recovers the cost of ensuring gas supply matches consumption on a daily basis.

General Service Rates: The Rate Schedules applicable to those Bundled Services for which a specific contract between the Company and the Applicant is not generally required. The General Service Rates include Rates 1, 6, and 9 of the Company.

Gigajoule ("GJ"): See Joule.

Hourly Demand: A contractually specified volume of gas applicable to service under a particular Rate Schedule which is the maximum volume of gas the Company is required to deliver to an Applicant on a hourly basis under a Service Contract.

Imperial Conversion Factors:

Volume:		
1,000 cubic feet (cf)	=	1 Mcf
	=	28.32784 cubic metres (m^3)
1 billion cubic feet (cf)	=	28.32784 $10^6 m^3$
Pressure:		
1 pound force per square inch (p.s.i.)	=	6.894757 kilopascals (kPa)
1 inch Water Column (in W.C.) (60°F)	=	0.249 kPa (15.5°C)
1 standard atmosphere	=	101.325 kPa
Energy:		
1 million British thermal units	=	1 MMBtu
	=	1.055056 gigajoules (GJ)
948,213.3 Btu	=	1 GJ
Monetary Value:		
$1 per Mcf	=	$0.03530096 per m^3
$1 per MMBtu	=	$0.9482133 per GJ

Interruptible Service: Gas service which is subject to curtailment for either capacity and/or supply reasons, at the option of the Company.

Intra-Alberta Service: Firm transportation service on the Nova pipeline system under which volumes are delivered to an Intra-Alberta point of acceptance.

Joule ("J"): The amount of work done when the point of application of a force of one newton is displaced a distance of one metre in the direction of the force. One megajoule ("MJ") means 1,000,000 joules; one gigajoule ("GJ") means 1,000,000,000 joules.

Large Volume Distribution Contract: (LVDC): A written agreement pursuant to which the Company agrees to supply and deliver gas to a specified Terminal Location.

Large Volume Distribution Contract Rates: The Rate Schedules applicable for annual consumption exceeding 340,000 cubic metres of gas per year and for which a specific contract between the Company and the Applicant is required.

Load-Balancing: The balancing of the gas supply to meet demand. Storage and other peak supply sources, curtailment of interruptible services, and diversions from one delivery point to another may be used by the Company.

Make-up Volume: A volume of gas nominated and delivered, pursuant to mutually agreed arrangements, by an Applicant to the Company for the purpose of reducing or eliminating a net debit balance in the Applicant's Banked Gas Account.

Mean Daily Volume (MDV): The volume of gas which an Applicant who delivers gas to the Company, under a T-Service arrangement, agrees to deliver to the Company each day in the term of the arrangement.

Metric Conversion Factors:

Volume:		
1 cubic metre (m^3)	=	35.30096 cubic feet (cf)
1,000 cubic metres	=	10^3m^3
	=	35,300.96 cf
	=	35.30096 Mcf
28.32784 m^3	=	1 Mcf
Pressure:		
1 kilopascal (kPa)	=	1,000 pascals
	=	0.145 pounds per square inch (p.s.i.)
101.325 kPa	=	one standard atmosphere
Energy:		
1 megajoule (MJ)	=	1,000,000 joules
	=	948.2133 British thermal units (Btu)
1 gigajoule (GJ)	=	948,213.3 Btu
1.055056 GJ	=	1 MMBtu
Monetary Value:		
\$1 per 10^3m^3	=	\$0.02832784 per Mcf
\$1 per gigajoule	=	\$1.055056 per MMBtu

Minimum Annual Volume: The minimum annual volume as stated in the customer's contract, also Section E.

Natural Gas: Natural and/or residue gas comprised primarily of methane.

Nominated Volume: The volume of gas which an Applicant has advised the Company it will deliver to the Company in a day.

Nominate, Nomination: The procedure of advising the Company of the volume which the Applicant expects to deliver to the Company in a day.

Ontario Energy Board: An agency of the Ontario Government which, amongst other things, approves the Company's Rate Schedules (Part V of this HANDBOOK) and the matters described in Parts III and IV of this HANDBOOK.

Point of Acceptance: The point at which the Company accepts delivery of a supply of natural gas for transportation to, or purchase from, the Applicant.

Rate Schedule: A numbered rate of the Company as fixed or approved by the OEB. that specifies rates, applicability, character of service, terms and conditions of service and the effective date.

Seasonal Credit: A credit applicable to Rate 135 customers to recognize the benefits they provide to the storage operations during the winter period.

Service Contract: An agreement between the Company and the Applicant which describes the responsibilities of each party in respect to the arrangements for the Company to provide Sales Service or Transportation Service to one or more Terminal Locations.

System Sales Service: A service of the Company in which the Company acquires and sells to the Applicant the Applicant's natural gas requirements.

T-Service: Transportation Service.

Terminal Location: The building or other facility of the Applicant at or in which natural gas will be used by the Applicant.

Transportation Service: A service in which the Company agrees to transport gas on the Applicant's behalf to a specified Terminal Location.

Unbundled Service: A service in which the demand for natural gas at a Terminal Location is met by the Applicant contracting for separate services (upstream transportation, load balancing/storage, transportation on the Company's distribution system) of which only Transportation Service is mandatory with the Company.

Western Canada Buy Price: The price per cubic metre which the Company would pay for gas pursuant to a Buy/Sell Agreement in which the purchase takes place in Western Canada.

RATES AND SERVICES AVAILABLE

The provisions of this PART II are intended to provide a general description of services offered by the Company and certain matters relating thereto. Such provisions are not definitive or comprehensive as to their subject matter and may be changed by the Company at any time without notice.

SECTION A - INTRODUCTION

1. In Franchise Services

Enbridge Gas Distribution provides in franchise services for the transportation of natural gas from the point of its delivery to Enbridge Gas Distribution to the Terminal Location at which the gas will be used. The natural gas to be transported may be owned by the Applicant for service or by the Company. In the latter case, it will be sold to the customer at the outlet of the meter located at the Terminal Location.

Applicants may elect to have the Company provide all-inclusively the services which are mutually agreed to be required or they may select (from the 300 series of rates, and Rate 125) only the amounts of those services which they consider they need.

The all-inclusive services are provided pursuant to Rates 1, 6 and 9, ("the General Service Rates") and Rates 100, 110, 115, 135, 145, and 170 ("the Large Volume Service Rates"). Individual services are available under Rates 125, 300, 315, and 316 ("the Unbundled Service Rates").

Service to residential locations is provided pursuant to Rate 1.

Service which may be interrupted at the option of the Company is available, at rates lower than would apply for equivalent service under a firm rate schedule, pursuant to Rates 145, 170. Under all other rate schedules, service is provided upon demand by the Applicant, i.e., on a firm service basis.

2. Ex-Franchise Services

Enbridge Gas Distribution provides ex-franchise services for the transportation of natural gas through its distribution system to a point of interconnection with the distribution system of other distributors of natural gas. Such service is provided pursuant to Rate 200 and provides for the bundled transportation of gas owned by the Company, owned by customers of that distributor, or owned by that distributor.

For the purposes of interpreting the terms and conditions contained in this Handbook of Rates and Distribution Services the ex - franchise distributor shall be considered to be the applicant for the transportation of its customer owned gas and shall assume all the obligations of transportation as if it owned the gas.

Nominations for transportation service must specify whether the volume to be transported is to displace firm or interruptible demand or general service.

In addition, the Company provides Compression, Storage, and Transmission services on its Tecumseh system under Rates 325, 330 and 331.

SECTION B - DIRECT PURCHASE ARRANGEMENTS

Applicants who purchase their natural gas requirements directly from someone other than the Company or who are brokers or agents for an end user, may arrange to transport gas on the Company's distribution network in conjunction with a Western Buy/Sell Arrangement or pursuant to an Ontario Delivery Transportation Service Arrangement, whether Bundled or Unbundled, or a Western Bundled Transportation Service Arrangement.

B. Western Canada

Buy/Sell in a Western Canada Buy/Sell Arrangement the Applicant delivers gas to a point in Western Canada which connects with the transmission pipeline of TransCanada PipeLines Limited. At that point, the Company purchases the gas from the Applicant at a price specified in Rider 'B' of the rate schedules less the costs for transmission of the gas from the point of purchase to a point in Ontario at which the Company's gas distribution network connects with a transmission pipeline system. The Company will not be entering into any new Western Canada buy/sell arrangements after April 1, 1999.

C. Ontario Delivery T-Service Arrangements

In an Ontario Delivery T-Service Arrangement the Applicant delivers gas, to a contractually agreed-upon point of acceptance in Ontario.

Delivery from the point of direct interconnection with the Company's gas distribution network to a Terminal Location served from the Company's gas distribution network may be obtained by the Applicant either under the Bundled Service Rate Schedules or under the Unbundled Service Rate Schedules.

(i) Bundled T-Service

Bundled T-Service is so called because all of the services required by the Applicant (delivery and load balancing) are provided for the prices specified in the applicable Rate Schedule. In a Bundled T-Service arrangement the Applicant contracts to deliver each day to the Company a Mean Daily Volume of gas. Fluctuations in the demand for gas at the Terminal Location are balanced by the Company.

(ii) Unbundled T-Service

The Unbundled Service Rates allow an Applicant to contract for only such kinds of service as the Applicant chooses. The potential advantage to an Applicant is that the chosen amounts of service may be less than the amounts required by an average customer represented in the applicable Rate Schedule, in which case the Applicant may be able to reduce the costs otherwise payable under Bundled T-Service.

D. Western Delivery T-Service Arrangement

In a Western Delivery T-Service Arrangement the Applicant contracts to deliver each day to a point on the TransCanada PipeLines Ltd. transmission system in Western Canada a Mean Daily Volume of gas plus fuel gas. Delivery from that point to the Terminal Location is carried out by the Company using its contracted capacity on the TransCanada PipeLines Limited. system and its gas distribution network. Unbundled T-Service in Ontario is not available with the Western Delivery Option.

An Applicant desiring to receive Transportation Service or to establish a Buy/Sell Agreement must first enter into the applicable written agreements with the Company.

PART III

TERMS AND CONDITIONS APPLICABLE TO ALL SERVICES

The provisions of this PART III are applicable to, and only to, Sales Service and Transportation Service.

SECTION A - AVAILABILITY

Unless otherwise stated in a Rate Schedule, the Company's rates and services are available throughout the entire franchised area serviced by the Company. Transportation service and/or sales service will be provided subject to the Company having the capacity in its gas distribution network to provide the service requested. When the Company is requested to supply the natural gas to be delivered, service shall be available subject to the Company having available to it a supply of gas adequate to meet the requirement without jeopardizing the supply to its existing customers.

Service shall be made available after acceptance by the Company of an application for service to a Terminal Location at which the natural gas will be used.

SECTION B - ENERGY CONTENT

The price of natural gas sold at a Terminal Location is based on the assumption that each cubic metre of such natural gas contains a certain number of megajoules of energy which number is specified in the Rate Schedules. Variations in cost resulting from the energy content of the gas actually delivered to the Company by its supplier(s) differing from the assumed energy content will be recorded and used to adjust future bills. Such adjustments shall be made in accordance with practices approved from time to time by the Ontario Energy Board.

SECTION C - SUBSTITUTION PROVISION

The Company may deliver gas from any standby equipment provided that the gas so delivered shall be reasonably equivalent to the natural gas normally delivered.

SECTION D - BILLS

Bills will be mailed or delivered monthly or at such other time period as set out in the Service Contract. Gas consumption to which the Company's rates apply will be determined by the Company either by meter reading or by the Company's estimate of consumption where meter reading has not occurred. The rates and charges applicable to a billing month shall be those applicable to the calendar month which includes the last day of the billing month.

SECTION E - MINIMUM BILLS

The minimum bill per month applicable to service under any particular Rate Schedule shall be the Customer Charge plus any applicable Contract Demand Charges for Delivery, Gas Supply Load Balancing, and Gas Supply and any applicable Direct Purchase Administration Charge, all as provided for in the applicable Rate Schedule.

In addition, for service under each of the Large Volume Distribution Contact Rates, if in a contract year a volume of gas equal to or greater than the product of the Contract Demand multiplied by a contractually specified multiple of the Contract Demand ("Minimum Annual Volume") is not taken at the Terminal Location the Applicant shall pay, in addition to the minimum monthly bills, the amount obtained when the difference between the Minimum Annual Volume and the volume taken in the contract year (such difference being the Annual Volume Deficiency) is multiplied by the applicable Minimum Bill Charge(s) as provided for in the applicable Rate Schedule. Notwithstanding the foregoing, the Minimum Annual Volume shall be the greater of the Minimum Annual Volume as determined above and 340,000 m^3.

If gas deliveries to the Terminal Location have been ordered to be curtailed or discontinued in a contract year at the request of the Company and have been curtailed or discontinued as ordered, the Minimum Annual Volume shall be reduced for each day of curtailment or discontinuance by the excess of the Contract Demand over the volume delivered to the Terminal Location on such day.

SECTION F - PAYMENT CONDITIONS

Enbridge Gas Distribution charges are due when the bill is received, which is considered to be three days after the date the bill is rendered, or within such other time period as set out in the Service Contract. A late payment charge of 1.5% per month (19.56% effectively per annum) of all of the unpaid Enbridge Gas Distribution charges, including all applicable federal and provincial taxes, is applied to the account on the seventeenth (17th) day following the date the bill is due.

SECTION G - TERM OF ARRANGEMENT

When gas service is provided and there is no written agreement in effect relating to the provision of such service, the term for which such service is to continue shall be one year. The term shall automatically be extended for a further year immediately following the expiry of any initial one year term or one year extension unless reasonable notice to terminate service is given to the Company, in a manner acceptable to the Company, prior to the expiry of the term. An Applicant receiving such service who temporarily discontinues service in the initial one year term or any one year extension and does not pay all the minimum bills for the period of such temporary discontinuance of service shall, upon the continuance of service, be liable to pay an amount equal to the unpaid minimum bills for such period. When a written agreement is in effect relating to the provision of gas service, the term for which such service is to continue shall be as provided for in the agreement.

SECTION H - RESALE PROHIBITION

Gas taken at a Terminal Location shall not be resold other than in accordance with all applicable laws and regulations and orders of any governmental authority or OEB having jurisdiction.

SECTION I - MEASUREMENT

The Company will install, operate and maintain at a Terminal Location such measurement equipment of suitable capacity and design as is required to measure the volume of gas delivered. Any special conditions for measurement are contained in the General Terms and Conditions which form part of each Large Volume Distribution Contract.

SECTION J - RATES IN CONTRACTS

Notwithstanding any rates for service specified in any Service Contract, the rates and charges provided for in an applicable Rate Schedule shall apply for service rendered on and after the effective date stated in such Rate Schedule until such Rate Schedule ceases to be applicable.

SECTION K - ADVICE RE: CURTAILMENT

The Company, if requested, will advise Applicants taking interruptible service of its estimate of service curtailment for the forthcoming winter. Such estimate will be provided as guidance to the Applicant in arranging for alternate fuel supply requirements. Abnormal weather and/or other unforeseen events may cause greater or lesser curtailment of service than expected.

SECTION L - DAILY DELIVERED VOLUMES

For purposes including that of calculating daily overrun gas volumes, the Company will recognize as having been delivered to it on a given day the sum of:

a) the volume of gas delivered under Intra-Alberta transportation arrangements, if any, plus;

b) the volume of gas delivered under FT transportation arrangements, if any, plus;

SECTION M - AUTHORIZED OVERRUN GAS

If an Applicant requests permission to exceed the Authorized Volume for a day, and such authorization is granted, such gas shall constitute Authorized Overrun Gas. Such gas shall either be sold by the Company to the Applicant pursuant to the provisions of Rate 320 applicable on such day, or, at the Company's sole discretion, under the Rate Schedule the customer is purchasing prior to such request. If the Applicant is supplying their own gas requirements and if the Applicant request and at the Company's sole discretion, such Overrun Gas will be debited to the Applicant's Banked gas Account.

SECTION N - UNAUTHORIZED SUPPLY OVERRUN GAS

If an Applicant for Transportation Service pursuant to the General Service Rates on any day delivers to the Company a Daily Delivered Volume which is less than the Mean Daily Volume, the volume of gas by which the Mean Daily Volume applicable to such day exceeds the Daily Delivered Volume delivered by the Applicant to the Company on such day shall constitute Unauthorized Supply Overrun Gas and shall be deemed to have been taken and purchased on such day. The rate applicable to such volume shall be 150% of the highest price on each day on which an overrun occurred for the calendar month as published in the Gas Daily for the Niagara and Iroquois export points for the CDA and the EDA delivery areas respectively.

Unauthorized Supply Overrun Gas for a day applicable to a Service Contract with an Applicant for service under the Large Volume Distribution Contract Rates is:

(a) the volume of gas by which the Daily Gas Quantity under the Service Contract on such day exceeds the Authorized Volume for such day, if any

plus

(b) if the day is in the months of December to March inclusive for an Applicant taking service on Rate 135 under Option a) or if the day is in the month of December under Option b), or if the day is a day on or in respect of which the Applicant has been requested in accordance with the Service Contract to curtail or discontinue the use of gas and the Service Contract is in whole or in part for interruptible Transportation Service, the volume of gas, if any, by which

(i) the Mean Daily Volume set out in the Service Contract and is applicable to such day exceeds

(ii) the Daily Delivered Volume delivered by the Applicant to the Company on such day, which excess volume of gas shall be deemed to have been taken and purchased by the Applicant on such day.

The Applicant shall pay the Company for Unauthorized Supply Overrun Gas at the rate applicable to Unauthorized Supply Overrun Gas as provided for in the Rate Schedule(s) applicable to the Service Contract.

An Applicant taking service pursuant to a Gas Delivery Agreement and a Large Volume Distribution Contract Rate must provide two business days notice to the Company of the Applicant's intention to deliver a Daily Delivered Volume which is less than the Mean Daily Volume for a specified time period. Failure to provide proper notice will result in Unauthorized Supply Overrun Gas calculated as the difference between Daily Delivered Volume and the Mean Daily Volume.

Unauthorized Supply Overrun Gas for a day applicable to a Service Contract with an Applicant for service under Rate 125 or Rate 300 shall be determined from the provisions of the applicable Rate Schedule. The Applicant shall pay the Company for Unauthorized Supply Overrun Gas at the rate applicable to Unauthorized Supply Overrun Gas as provided for in the Rate Schedule(s) applicable to the Service Contract.

SECTION O – COMPANY RESPONSIBILTY AND LIABILITY

This Section O applies only to gas distribution service under Rates 1, 6 and 9, and does not replace or supercede the terms in any applicable Service Contract.
The Company shall make reasonable efforts to maintain, but does not guarantee, continuity of gas service to its customers. The Company may, in its sole discretion, terminate or interrupt gas service to customers;

to maintain safety and reliability on, or to facilitate construction, installation, maintenance, repair, replacement or inspection of the Company's facilities; or

for any reason related to dangerous or hazardous circumstances, emergencies or Force Majeure.

The Company shall not be liable for any loss, injury, damage, expense, charge, cost or liability of any kind, whether direct, indirect, special or consequential in nature, (excepting only direct physical loss, injury or damage to a customer or a customer's property, resulting from the negligent acts or omissions of the Company, its employees or agents) arising from or connected with any failure, defect, fluctuation or interruption in the provision of gas service by the Company to its customers.

PART IV

TERMS AND CONDITIONS – DIRECT PURCHASE ARRANGEMENTS

Any Applicant, at the time of applying for service, may elect, in and for the term of any Service Contract, to deliver its own natural gas requirements to the Company and the Company shall deliver gas to a Terminal Location as required by the Applicant, subject to the terms and conditions contained in the applicable Rate Schedule and in the Service Contract. For Buy/Sell Arrangements and Bundled T-Service the deliveries by the Applicant to the Company shall be at the Applicant's estimated mean daily rate of consumption.

Backstopping of an Applicant's natural gas supply for Transportation Service arrangements will be available pursuant to Rate 320 subject to the Company's ability to do so using reasonable commercial efforts. Gas Purchase Agreements in respect to Buy/Sell Arrangements shall specify terms and conditions available to the Company to alleviate certain consequences of the Applicant's failure to deliver the required volume of gas.

The following Terms and Conditions shall apply to, and only to, Transportation Service and/or Gas Purchase Agreements.

SECTION A - NOMINATIONS

An Applicant delivering gas to the Company pursuant to a contract is responsible for advising the Company, by means of a contractually specified Nomination procedure, of the daily volume of gas to be delivered to the Company by or on behalf of the Applicant.

An initial daily volume must be Nominated by a contractually specified time before the first day on which gas is to be delivered to the Company. Any Nomination, once accepted by the Company, shall be considered as a standing nomination applicable to each subsequent day in a contract term unless specifically varied by written notice to the Company.

A contract may specify certain contractual provisions that are applicable in the event that an Applicant either fails to advise of a revised daily nomination or fails to deliver the daily volume so nominated.

A Nominated Volume in excess of the Applicant's Maximum Daily Volume as specified in the Service Contract will not be accepted except as specifically provided for in any contract.

SECTION B - OBLIGATION TO DELIVER

During any period of curtailment or discontinuance of Bundled interruptible Transportation Service as ordered by the Company, any Applicant supplying its own gas requirements must, on such day, deliver to the Company the Mean Daily Volume of gas specified in any Service Contract.

Each Applicant taking service pursuant to a Gas Delivery Agreement and a Large Volume Distribution Contract Rate is obligated to deliver the Mean Daily Volume of gas as specified in any Service Contract, unless the Applicant provides two business days notice to the Company of the Applicant's intention to deliver a Daily Delivered Volume which is less than the Mean daily Volume for a specified time period.

An Applicant taking service on Rate 135 under Option a) must deliver to the Company the Mean Daily Volume of gas specified in the Service Contract in the months of December to March, inclusive.

An Applicant taking service on Rate 135 under Option b) must deliver to the Company the Modified Mean Daily Volume of gas specified in the Service Contract in the month of December.

Applicants taking service on General Service rates pursuant to a Direct Purchase Agreement must, on each day in the term of such agreement, deliver to the Company the Mean Daily Volume of gas specified in such agreement.

SECTION C - DIVERSION RIGHTS

Subject to compliance with the Terms and Conditions of all Required Orders, an Applicant who has entered into a Transportation Service Agreement or Agreements which provide(s) for deliveries to the Company for more than one Terminal Location shall have the right, on such terms and only on such terms as are specified in the applicable Transportation Service Agreement, to divert deliveries from one or more contractually specified Terminal Locations to other contractually specified Terminal Locations.

SECTION D - BANKED GAS ACCOUNT (BGA)

For T-Service Applicants, the Company shall keep a record ("Banked Gas Account") of the volume of gas delivered by the Applicant to the Company in respect of a Terminal Location (credits) and of the volume of gas taken by the Applicant at the Terminal Location (debits). (Any volume of gas sold by the Company to the Applicant in respect to the Terminal Location shall not be debited to the Banked Gas Account). The Company shall periodically report to the Applicant the net balance in the Applicant's Banked Gas Account.

SECTION E - DISPOSITION OF BANKED GAS ACCOUNT (BGA) BALANCES

A. The following Terms and Conditions shall apply to Bundled T-Service:

(a) At the end of each contract year, disposition of any net debit balance in the Banked Gas Account (BGA) shall be made as follows:

The Applicant, by written notice to the Company within thirty (30) days of the end of the contract year, may elect to return to the Company, in kind, during the one hundred and eighty (180) days following the end of the contract year, that portion of any debit balance in the Banked Gas Account as at the end of the contract year not exceeding a volume of twenty times the Applicant's Mean Daily Volume by the Applicant delivering to the Company on days agreed upon by the Company and the Applicant a volume of gas greater than the Mean Daily Volume, if any, applicable to such day under a Service Contract. Any volume of gas returned to the Company as aforesaid shall not be credited to the Banked Gas Account in the subsequent contract year. Any debit balance in the Banked Gas Account as at the end of the contract year which is not both elected to be returned, and actually returned, to the Company as aforesaid shall be deemed to have been sold to the Applicant and the Applicant shall pay for such gas within ten (10) days of the rendering of a bill therefor. The rate applicable to such gas shall be:

(1) for *Bundled Western T-Service*, 120% of the average price over the contracted year, based on the published index price for the Monthly AECO/NIT supply adjusted for Nova's AECO to Empress transportation tolls and compressor fuel costs.

(2) for *Bundled Ontario T-Service*, 120% of the average price over the contracted year, based on the published index price for the Monthly AECO/NIT supply adjusted for Nova's AECO to Empress transportation tolls and compressor fuel costs, plus the Company's average transportation cost to its franchise area over the contract year.

(b) A credit balance in the Banked Gas Account as at the end of the contract year must be eliminated in one or more of the following manners, namely:

(i) Subject to clause (ii), if the Applicant continues to take service from the Company under a contract pursuant to which the Applicant delivers gas to the Company and the Applicant so elects (by written notice to the Company within thirty (30) days of the end of the contract year), that portion of such balance which the Applicant stipulates in such written notice and which does not exceed twenty times the Applicant's Mean Daily Volume may be carried forward as a credit to the Banked Gas Account for the next succeeding contract year. Any volume duly elected to be carried forward under this clause shall, and may only, be reduced within the period of one hundred and eighty (180) days ("Adjustment Period") immediately following the contract year, by the Applicant delivering to the Company, on days in the Adjustment Period agreed upon by the Company and the Applicant ("Adjustment Days"), a volume of gas less than the Mean Daily Volume applicable to such day under a Service Contract. Subject to the foregoing, the credit balance in the Banked Gas Account shall be deemed to be reduced on each Adjustment Day by the volume ("Daily Reduction Volume") by which the Mean Daily Volume applicable to such day exceeds the greater of the volume of gas delivered by the Applicant on such day and the Nominated Volume for such day which was accepted by the Company.

(ii) Any portion of a credit balance in the Banked Gas Account which is not eligible to be eliminated in accordance with clause (i), or which the Applicant elects (by written notice to the Company within thirty (30) days of the end of the contract year) to sell under this clause, shall be deemed to have been tendered for sale to the Company and the Company shall purchase such portion at:

(1) for *Bundled Western T*-Service, a price per cubic metre of eighty percent (80%) of the average price over the contract year, based on the published index price for the Monthly AECO/NIT supply adjusted for Nova's AECO to Empress transportation tolls and compressor fuel costs, less the Company's average transportation cost to its franchise area over the contract year.

(2) for *Bundled Ontario T-Service*, a price per cubic metre of eighty percent (80%) of the average price over the contract year, based on the published index price for the Monthly AECO/NIT supply adjusted for Nova's AECO to Empress transportation tolls and compressor fuel costs.

Any volume of gas deemed to have been so tendered for sale shall be deemed to have been eliminated from the credit balance of the Banked Gas Account.

During the Adjustment Period the Company shall use reasonable efforts to accept the Applicant's reduced gas deliveries. Any credit balance in the Banked Gas Account not eliminated as aforesaid in the Adjustment Period shall be forfeited to, and be the property of, the Company, and such volume of gas shall be debited to the Banked Gas Account as at the end of the Adjustment Period.

Subject to its ability to do so, the Company will attempt to accommodate arrangements which would permit adjustments to Banked Gas Account balances at times and in a manner which are mutually agreed upon by the Applicant and the Company.

B. The following Terms and Conditions shall apply to Unbundled Service:

The Terms and Conditions for disposition of Cumulative Imbalance Account balances shall be as specified in the applicable Service Contracts.

RATE NUMBER: 1	RESIDENTIAL SERVICE

APPLICABILITY:

To any Applicant needing to use the Company's natural gas distribution network to have transported a supply of natural gas to a residential building served through one meter and containing no more than six dwelling units ("Terminal Location").

RATE:

Rates per cubic metre assume an energy content of 37.69 MJ/m³.

	Billing Month January to December
Monthly Customer Charge	**$19.00**
Delivery Charge per cubic metre	
For the first 30 m³ per month	**8.0112 ¢/m³**
For the next 55 m³ per month	**7.5405 ¢/m³**
For the next 85 m³ per month	**7.1717 ¢/m³**
For all over 170 m³ per month	**6.8971 ¢/m³**
Transportation Charge per cubic metre	**4.8217 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**15.4553 ¢/m³**

The rates quoted above shall be subject to the Gas Cost Adjustment contained in Rider "C" and the Revenue Adjustment Rider contained in Rider "E". Also, meter readings will be adjusted by the Atmospheric Pressure Factor relevant to the customer's location as shown in Rider "F".
The Gas Supply Charge is applicable if the Applicant is not providing its own supply of natural gas for transportation.

DIRECT PURCHASE ARRANGEMENTS:

Rider "A" or Rider "B" shall be applicable to Applicants who enter into Direct Purchase Arrangements under this Rate Schedule.

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after January 1, 2011 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2011 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2010 and that indicates as the Board Order, EB-2010-0258, effective October 1, 2010.

APPLICABILITY:

To any Applicant needing to use the Company's natural gas distribution network to have transported a supply of natural gas to a single terminal location ("Terminal Location") for non-residential purposes.

RATE:

Rates per cubic metre assume an energy content of 37.69 MJ/m³.

		Billing Month January to December
Monthly Customer Charge		**$65.00**
Delivery Charge per cubic metre		
For the first	500 m³ per month	**7.6076 ¢/m³**
For the next	1050 m³ per month	**5.9685 ¢/m³**
For the next	4500 m³ per month	**4.8211 ¢/m³**
For the next	7000 m³ per month	**4.0835 ¢/m³**
For the next	15250 m³ per month	**3.7558 ¢/m³**
For all over	28300 m³ per month	**3.6738 ¢/m³**
Transportation Charge per cubic metre		**4.8217 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)		**15.5199 ¢/m³**

The rates quoted above shall be subject to the Gas Cost Adjustment contained in Rider "C" and the Revenue Adjustment Rider contained in Rider "E". Also, meter readings will be adjusted by the Atmospheric Pressure Factor relevant to the customer's location as shown in Rider "F".
The Gas Supply Charge is applicable if the Applicant is not providing its own supply of natural gas for transportation.

DIRECT PURCHASE ARRANGEMENTS:

Rider "A" or Rider "B" shall be applicable to Applicants who enter into Direct Purchase Arrangements under this Rate Schedule.

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after January 1, 2011 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2011 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2010 and that indicates as the Board Order, EB-2010-0258, effective October 1, 2010.

RATE NUMBER: 9	CONTAINER SERVICE

APPLICABILITY:

To any Applicant needing to use the Company's natural gas distribution network to have transported a supply of natural gas to a single terminal location ("Terminal Location") at which, such gas is authorized by the Company to be resold by filling pressurized containers.

RATE:

Rates per cubic metre assume an energy content of 37.69 MJ/m³.

	Billing Month January to December
Monthly Customer Charge	**$235.89**
Delivery Charge per cubic metre	
For the first 20,000 m³ per month	**10.7807 ¢/m³**
For all over 20,000 m³ per month	**10.0912 ¢/m³**
Transportation Charge per cubic metre	**4.8217 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**15.3448 ¢/m³**

The rates quoted above shall be subject to the Gas Cost Adjustment contained in Rider “C” and the Revenue Adjustment Rider contained in Rider "E". In addition, meter readings will be adjusted by the Atmospheric Pressure Factor relevant to the customer’s location as shown in Rider "F". The Gas Supply Charge is applicable if the Applicant is not providing its own supply of natural gas for transportation.

DIRECT PURCHASE ARRANGEMENTS:

Rider "A" or Rider "B" shall be applicable to Applicants who enter into Direct Purchase Arrangements under this Rate Schedule.

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after January 1, 2011 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2011 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2010 and that indicates as the Board Order, EB-2010-0258, effective October 1, 2010.

APPLICABILITY:

To any Applicant who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation, to a single terminal location ("Terminal Location"), of a specified annual volume of natural gas of not less than 340,000 cubic metres to be delivered at a specified maximum daily rate.

CHARACTER OF SERVICE:

Service shall be continuous (firm) except for events as specified in the Service Contract including force majeure.

RATE:

Rates per cubic metre assume an energy content of 37.69 MJ/m³.

	Billing Month January to December
Monthly Customer Charge	**$122.01**
Delivery Charge	
Per cubic metre of Contract Demand	**8.1900 ¢/m³**
For the first 14,000 m³ per month	**5.1303 ¢/m³**
For the next 28,000 m³ per month	**3.7713 ¢/m³**
For all over 42,000 m³ per month	**3.2123 ¢/m³**
Gas Supply Load Balancing Charge	**0.5055 ¢/m³**
Transportation Charge per cubic metre	**4.8217 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**15.3588 ¢/m³**

The rates quoted above shall be subject to the Gas Cost Adjustment contained in Rider “C” and the Revenue Adjustment Rider contained in Rider "E". In addition, meter readings will be adjusted by the Atmospheric Pressure Factor relevant to the customer’s location as shown in Rider "F". The Gas Supply Charge is applicable if the Applicant is not providing its own supply of natural gas for transportation.

DIRECT PURCHASE ARRANGEMENTS:

Rider "A" or Rider "B" shall be applicable to Applicants who enter into Direct Purchase Arrangements under this Rate Schedule.

UNAUTHORIZED OVERRUN GAS RATE:

When the Applicant takes Unauthorized Supply Overrun Gas, the Applicant shall purchase such gas at a rate of 150% of the highest price on each day on which an overrun occurred for the calendar month as published in the Gas Daily for the Niagara and Iroquois export points for the CDA and EDA respectively.

On the second and subsequent occasion in a contract year when the Applicant takes Unauthorized Demand Overrun Gas, a new Contract Demand will be established and shall be charged equal to 120% of the applicable monthly charge for twelve months of the current contract term, including retroactively based on the terms of the Service Contract.

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency
(See Terms and Conditions of Service):

10.4146 ¢/m³

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after January 1, 2011 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2011 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2010 and that indicates as the Board Order, EB-2010-0258, effective October 1, 2010.

RATE NUMBER: **110**	**LARGE VOLUME LOAD FACTOR SERVICE**

APPLICABILITY:

To any Applicant who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation, to a single terminal location ("Terminal Location"), of an annual supply of natural gas of not less than 183 times a specified maximum daily volume of not less than 1,865 cubic metres.

CHARACTER OF SERVICE:

Service shall be continuous (firm) except for events as specified in the Service Contract including force majeure.

RATE:

Rates per cubic metre assume an energy content of 37.69 MJ/m³.

	Billing Month
	January to December
Monthly Customer Charge	**$587.37**
Delivery Charge	
Per cubic metre of Contract Demand	**22.9100 ¢/m³**
Per cubic metre of gas delivered	
For the first 1,000,000 m³ per month	**0.6000 ¢/m³**
For all over 1,000,000 m³ per month	**0.4500 ¢/m³**
Gas Supply Load Balancing Charge	**0.1400 ¢/m³**
Transportation Charge per cubic metre	**4.8217 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**15.3448 ¢/m³**

The rates quoted above shall be subject to the Gas Cost Adjustment contained in Rider “C” and the Revenue Adjustment Rider contained in Rider "E". In addition, meter readings will be adjusted by the Atmospheric Pressure Factor relevant to the customer’s location as shown in Rider "F". The Gas Supply Charge is applicable if the Applicant is not providing its own supply of natural gas for transportation.

DIRECT PURCHASE ARRANGEMENTS:

Rider "A" or Rider "B" shall be applicable to Applicants who enter into Direct Purchase Arrangements under this Rate Schedule.

UNAUTHORIZED OVERRUN GAS RATE:

When the Applicant takes Unauthorized Supply Overrun Gas, the Applicant shall purchase such gas at a rate of 150% of the highest price on each day on which an overrun occurred for the calendar month as published in the Gas Daily for the Niagara and Iroquois export points for the CDA and EDA respectively.

On the second and subsequent occasion in a contract year when the Applicant takes Unauthorized Demand Overrun Gas, a new Contract Demand will be established and shall be charged equal to 120% of the applicable monthly charge for twelve months of the current contract term, including retroactively based on the terms of the Service Contract.

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency
(See Terms and Conditions of Service):

5.5189 ¢/m³

In determining the Annual Volume Deficiency, the minimum bill multiplier shall not be less than 183.

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after January 1, 2011 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2011 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2010 and that indicates as the Board Order, EB-2010-0258, effective October 1, 2010.

APPLICABILITY:

To any Applicant who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation, to a single terminal location ("Terminal Location"), of an annual supply of natural gas of not less than 292 times a specified maximum daily volume of not less than 1,165 cubic metres.

CHARACTER OF SERVICE:

Service shall be continuous (firm) except for events as specified in the Service Contract including force majeure.

RATE:

Rates per cubic metre assume an energy content of 37.69 MJ/m³.

	Billing Month January to December
Monthly Customer Charge	**$622.62**
Delivery Charge	
Per cubic metre of Contract Demand	**24.3600 ¢/m³**
Per cubic metre of gas delivered	
For the first 1,000,000 m³ per month	**0.3287 ¢/m³**
For all over 1,000,000 m³ per month	**0.2287 ¢/m³**
Gas Supply Load Balancing Charge	**0.0472 ¢/m³**
Transportation Charge per cubic metre	**4.8217 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**15.3448 ¢/m³**

The rates quoted above shall be subject to the Gas Cost Adjustment contained in Rider “C” and the Revenue Adjustment Rider contained in Rider "E". In addition, meter readings will be adjusted by the Atmospheric Pressure Factor relevant to the customer’s location as shown in Rider "F". The Gas Supply Charge is applicable if the Applicant is not providing its own supply of natural gas for transportation.

DIRECT PURCHASE ARRANGEMENTS:

Rider "A" or Rider "B" shall be applicable to Applicants who enter into Direct Purchase Arrangements under this Rate Schedule.

UNAUTHORIZED OVERRUN GAS RATE:

When the Applicant takes Unauthorized Supply Overrun Gas, the Applicant shall purchase such gas at a rate of 150% of the highest price on each day on which an overrun occurred for the calendar month as published in the Gas Daily for the Niagara and Iroquois export points for the CDA and EDA respectively.

On the second and subsequent occasion in a contract year when the Applicant takes Unauthorized Demand Overrun Gas, a new Contract Demand will be established and shall be charged equal to 120% of the applicable monthly charge for twelve months of the current contract term, including retroactively based on the terms of the Service Contract.

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency
(See Terms and Conditions of Service):

5.1547 ¢/m³

In determining the Annual Volume Deficiency the minimum bill multiplier shall not be less than 292.

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after January 1, 2011 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2011 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2010 and that indicates as the Board Order, EB-2010-0258, effective October 1, 2010.

APPLICABILITY:

To any Applicant who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation, to a single terminal location ("Terminal Location"), of a specified maximum daily volume of natural gas. The maximum daily volume for billing purposes, Contract Demand or Billing Contract Demand, as applicable, shall not be less than 600,000 cubic metres. The Service under this rate requires Automatic Meter Reading (AMR) capability.

CHARACTER OF SERVICE:

Service shall be firm except for events specified in the Service Contract including force majeure.

For Non-Dedicated Service the monthly demand charges payable shall be based on the Contract Demand which shall be 24 times the Hourly Demand and the Applicant shall not exceed the Hourly Demand.

For Dedicated Service the monthly demand charges payable shall be based on the Billing Contract Demand or the Contract Demand specified in the Service Contract. The Applicant shall not exceed an hourly flow calculated as 1/24th of the Contract Demand specified in the Service Contract.

DISTRIBUTION RATES:

The following rates and charges, as applicable, shall apply for deliveries to the Terminal Location.

Monthly Customer Charge	**$500.00**
Demand Charge Per cubic metre of the Contract Demand or the Billing Contract Demand, as applicable, per month	**9.0792 ¢/m³**
Direct Purchase Administration Charge	**$75.00**
Forecast Unaccounted For Gas Percentage	**0.3%**

Monthly Minimum Bill: The Monthly Customer Charge plus the Monthly Demand Charge.

TERMS AND CONDITIONS OF SERVICE:

1. To the extent that this Rate Schedule does not specifically address matters set out in PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** then the provisions in those Parts shall apply, as contemplated therein, to service under this Rate Schedule.

2. **Unaccounted for Gas (UFG) Adjustment Factor**:

   The Applicant is required to deliver to the Company on a daily basis the sum of: (a) the volume of gas to be delivered to the Applicant's Terminal Location; and (b) a volume of gas equal to the forecast unaccounted for gas percentage as stated above multiplied by (a). In the case of a Dedicated Service, the Unaccounted for Gas volume requirement is not applicable.

3. **Nominations**:

   Customer shall nominate gas delivery daily based on the gross commodity delivery required to serve the customer’s daily load plus the UFG. Customers may change daily nominations based on the nomination windows within a day as defined by the customer contract with TransCanada PipeLines (TCPL) or Union Gas Limited.

   Schedule of nominations under Rate 125 has to match upstream nominations. This rate does not allow for any more flexibility than exists upstream of the EGD gas distribution system. Where the customer’s nomination does not match the confirmed upstream nomination, the nomination will be confirmed at the upstream value.

   Customer may nominate gas to a contractually specified Primary Delivery Area that may be EGD’s Central Delivery Area (CDA) or EGD’s Eastern Delivery Area (EDA) or other Delivery Area as specified in the applicable Service Contract. The Company may accept deliveries at a Secondary Delivery Area such as Dawn, at its sole discretion. Quantities of gas nominated to the system cannot exceed the Contract Demand, unless Make-up Gas or Authorized Overrun is permitted.

Customers with multiple Rate 125 contracts within a Primary Delivery Area may combine nominations subject to system operating requirements and subject to the Contract Demand for each Terminal Location. For combined nominations the customer shall specify the quantity of gas to each Terminal Location and the order in which gas is to be delivered to each Terminal Location. The specified order of deliveries shall be used to administer Load Balancing Provisions to each Terminal Location. When system conditions require delivery to a single Terminal Location only, nominations with different Terminal Locations may not be combined.

The Company permits pooling of Rate 125 contracts for legally related customers who meet the Business Corporations Act (Ontario) ("OBCA") definition of "affiliates" to allow for the management of those contracts by a single manager. The single manager is jointly liable with the individual customers for all of their obligations under the contracts, while the individual customers are severally liable for all of their obligations under their own contracts.

4. **Authorized Demand Overrun:**

The Company may, at its sole discretion, authorize consumption of gas in excess of the Contract Demand for limited periods within a month, provided local distribution facilities have sufficient capacity to accommodate higher demand. In such circumstances, customer shall nominate gas delivery based on the gross commodity delivery (the sum of the customer's Contract Demand and the authorized overrun amount) required to serve the customer's daily load, plus the UFG. In the event that gas usage exceeds the gas delivery on a day where demand overrun is authorized, the excess gas consumption shall be deemed Supply Overrun Gas.
Such service shall not exceed 5 days in any contract year. Based on the terms of the Service Contract, requests beyond 5 days will constitute a request for a new Contract Demand level with retroactive charges. The new Contract Demand level may be restricted by the capability of the local distribution facilities to accommodate higher demand.

Automatic authorization of transportation overrun over the Billing Contract Demand will be given in the case of Dedicated Service to the Terminal Location provided that pipeline capacity is available and subject to the Contract Demand as specified in the Service Contract.

Authorized Demand Overrun Rate	**0.30 ¢/m³**

The Authorized Demand Overrun Rate may be applied to commissioning volumes at the Company's sole discretion, for a contractual period of not more than one year, as specified in the Service Contract.

5. **Unauthorized Demand Overrun:**

Any gas consumed in excess of the Contract Demand and/or maximum hourly flow requirements, if not authorized, will be deemed to be Unauthorized Demand Overrun gas. Unauthorized Demand Overrun gas may establish a new Contract Demand effective immediately and shall be subject to a charge equal to 120 % of the applicable monthly charge for twelve months of the current contract term, including retroactively based on terms of Service Contract. Based on capability of the local distribution facilities to accommodate higher demand, different conditions may apply as specified in the applicable Service Contract. Unauthorized Demand Overrun gas shall also be subject to Unauthorized Supply Overrun provisions.

6. **Unauthorized Supply Overrun:**

Any volume of gas taken by the Applicant on a day at the Terminal Location which exceeds the sum of:

i. any applicable provisions of Rate 315 and any applicable Load Balancing Provision pursuant to Rate 125, plus

ii. the volume of gas delivered by the Applicant on that day shall constitute Unauthorized Supply Overrun Gas.

The Company may also deem volumes of gas to be Unauthorized Supply Overrun gas in other circumstances, as set out in the Load Balancing Provisions of Rate 125.

Any gas deemed to be Unauthorized Overrun gas shall be purchased by the customer at a price (Pe), which is equal to 150% of the highest price in effect for that day as defined below*****.

7. **Unauthorized Supply Underrun:**

Any volume of gas delivered by the Applicant on any day in excess of the sum of:

i. any applicable provisions of Rate 315 and any applicable Load Balancing Provision pursuant to Rate 125, plus

ii. the volume of gas taken by the Applicant at the Terminal Location on that day shall be classified as Supply Underrun Gas.

The Company may also deem volumes of gas to be Unauthorized Supply Underrun gas in other circumstances, as set out in the Load Balancing Provisions of Rate 125.

Any gas deemed to be Unauthorized Supply Underrun Gas shall be purchased by the Company at a price (P_u) which is equal to fifty percent (50%) of the lowest price in effect for that day as defined below**.

* where the price P_e expressed in cents / cubic metre is defined as follows:
$P_e = (P_m * E_r * 100 * 0.03769 / 1.055056) * 1.5$

P_m = highest daily price in U.S. $/mmBtu published in the Gas Daily, a Platts Publication, for that day under the column "Absolute", for the Niagara export point if the terminal location is in the CDA delivery area, and the Iroquois export point if the terminal location is in the EDA delivery area.

E_r = Noon day spot exchange rate expressed in Canadian dollars per U.S. dollar for such day quoted by the Bank of Canada in the following day's Globe & Mail Publication.

1.055056 = Conversion factor from mmBtu to GJ.

0.03769 = Conversion factor from GJ to cubic metres.

** where the price P_u expressed in cents / cubic metre is defined as follows:
$P_u = (P_l * E_r * 100 * 0.03769 / 1.055056) * 0.5$

P_l = lowest daily price in U.S. $/mmBtu published in the Gas Daily, a Platts Publication, for that day under the column "Absolute", for the Niagara export point if the terminal location is in the CDA delivery area, and the Iroquois export point if the terminal location is in the EDA delivery area.

Term of Contract:

A minimum of one year. A longer-term contract may be required if incremental contracts/assets/facilities have been procured/built for the customer. Migration from an unbundled rate to bundled rate may be restricted subject to availability of adequate transportation and storage assets.

Right to Terminate Service:

The Company reserves the right to terminate service to customers served hereunder where the customer's failure to comply with the parameters of this rate schedule, including the load balancing provisions, jeopardizes either the safety or reliability of the gas system. The Company shall provide notice to the customer of such termination; however, no notice is required to alleviate emergency conditions.

LOAD BALANCING PROVISIONS:

Load Balancing Provisions shall apply at the customer's Terminal Location or at the location of the meter installation for a customer served from a dedicated facility. In the event of an imbalance any excess delivery above the customer's actual consumption or delivery less than the actual consumption shall be subject to the Load Balancing Provisions.

Definitions:

Aggregate Delivery:

The Aggregate Delivery for a customer's account shall equal the sum of the confirmed nominations of the customer for delivery of gas to the applicable delivery area from all pipeline sources including where applicable, the confirmed nominations of the customer for Storage Service under Rate 316 or Rate 315 and any available No-Notice Storage Service under Rate 315 for delivery of gas to the Applicable Delivery Area.

Applicable Delivery Area:

The Applicable Delivery Area for each customer shall be specified by contract as a Primary Delivery Area. Where system-operating conditions permit, the Company, in its sole discretion, may accept a Secondary Delivery Area as the Applicable Delivery Area by confirming the customer's nomination of such area. Confirmation of a Secondary Delivery Area for a period of a gas day shall cause such area to become the Applicable Delivery Area for such day. Where delivery occurs at both a Terminal Location and a Secondary Delivery Area on a given day, the sum of the confirmed deliveries may not exceed the Contract Demand, unless Demand Overrun and/or Make-up Gas is authorized.

Primary Delivery Area:

The Primary Delivery Area shall be delivery area such as EGD's Central Delivery Area (CDA) or EGD's Eastern Delivery Area (EDA), or other Delivery Area as specified in the applicable Service Contract.

Secondary Delivery Area:

A Secondary Delivery Area may be a delivery area such as Dawn where the Company, at its sole discretion, determines that operating conditions permit gas deliveries for a customer.

Actual Consumption:

The Actual Consumption of the customer shall be the metered quantity of gas consumed at the customer's Terminal Location or in the event of combined nominations at the Terminal Locations specified.

Net Available Delivery:

The Net Available Delivery shall equal the Aggregate Delivery times one minus the annually determined percentage of Unaccounted for Gas (UFG) as reported by the Company.

Daily Imbalance:

The Daily Imbalance shall be the absolute value of the difference between Actual Consumption and Net Available Delivery.

Cumulative Imbalance:

The Cumulative Imbalance shall be the sum of the difference between Actual Consumption and Net Available Delivery since the date the customer last balanced or was deemed to have balanced its Cumulative Imbalance account.

Maximum Contractual Imbalance:

The Maximum Contractual Imbalance shall be equal to 60% of the customer's Contract Demand for non dedicated service and 60% of the Billing Contract Demand for dedicated service.

Winter and Summer Seasons:

The winter season shall commence on the date that the Company provides notice of the start of the winter period and conclude on the date that the Company provides notice of the end of the winter period. The summer season shall constitute all other days. The Company shall provide advance notice to the customer of the start and end of the winter season as soon as reasonably possible, but in no event not less than 2 days prior to the start or end.

Operational Flow Order:

An Operational Flow Order (OFO) shall constitute an issuance of instructions to protect the operational capacity and integrity of the Company's system, including distribution and/or storage assets, and/or connected transmission pipelines.

Enbridge Gas Distribution, acting reasonably, may call for an OFO in the following circumstances:

- Capacity constraint on the system, or portions of the system, or upstream systems, that are fully utilized;
- Conditions where the potential exists that forecasted system demand plus reserves for short notice services provided by the Company and allowances for power generation customers' balancing requirements would exceed facility capabilities and/or provisions of 3rd party contracts;
- Pressures on the system or specific portions of the system are too high or too low for safe operations;
- Storage system constraints on capacity or pressure or caused by equipment problems resulting in limited ability to inject or withdraw from storage;
- Pipeline equipment failures and/or damage that prohibits the flow of gas;
- Any and all other circumstances where the potential for system failure exists.

Daily Balancing Fee:

On any day where the customer has a Daily Imbalance the customer shall pay a Daily Balancing Fee equal to:

(Tier 1 Quantity X Tier 1 Fee) + (Tier 2 Quantity X Tier 2 Fee) + (Applicable Penalty Fee for Imbalance in excess of the Maximum Contractual Imbalance X the amount of Daily Imbalance in excess of the Maximum Contractual Imbalance)

Where Tier 1 and 2 Fees and Quantities are set forth as follows:

Tier 1 = 0.7255 cents/m3 applied to Daily Imbalance of greater than 2% but less than 10% of the Maximum Contractual Imbalance

Tier 2 = 0.8706 cents/m3 applied to Daily Imbalance of greater than 10% but less than the Maximum Contractual Imbalance

In addition for Tier 2, instances where the Daily Imbalance represents an under delivery of gas during the winter season shall constitute Unauthorized Supply Overrun Gas for all gas in excess of 10% of Maximum Contractual Imbalance. Where the Daily Imbalance represents an over delivery of gas during the summer season, the Company reserves the right to deem as Unauthorized Supply Underrun Gas for all gas in excess of 10% of Maximum Contractual Imbalance. The Company will issue a 24-hour advance notice to customers of its intent to impose cash out for over delivery of gas during the summer season.

For customers delivering to a Primary Delivery Area other than EGD's CDA or EGD's EDA, the Tier 1 Fee is applied to Daily Imbalance of greater than 0% but less than 10% of the Maximum Contractual Imbalance

The customers shall also pay any Limited Balancing Agreement (LBA) charges imposed by the pipeline on days when the customer has a Daily Imbalance provided such imbalance matches the direction of the pipeline imbalance. LBA charges shall first be allocated to customers served under Rates 125 and 300. The system bears a portion of these charges only to the extent that the system incurs such charges based on its operation excluding the operation of customers under Rates 125 and 300. In that event, LBA charges shall be prorated based on the relative imbalances. The Company will provide the customer with a derivation of any such charges.

Customer’s Actual Consumption cannot exceed Net Available Delivery when the Company issues an Operational Flow Order in the winter. Net nominations must not be less than consumption at the Terminal Location. Any negative Daily Imbalance on a winter Operational Flow Order day shall be deemed to be Unauthorized Supply Overrun. Customer’s Net Available Delivery cannot exceed Actual Consumption when the Company issues an Operational Flow Order in the summer. Actual Consumption must not be less than net nomination at the Terminal Location. Any positive Daily Imbalance on a summer Operational Flow Order day shall be deemed to be Unauthorized Supply Underrun.

The Company will waive Daily Balancing Fee and Cumulative Imbalance Charge on the day of an Operational Flow Order if the customer used less gas that the amount the customer delivered to the system during the winter season or the customer used more gas than the amount the customer delivered to the system during the summer season. The Company will issue a 24-hour advance notice to customers of Operational Flow Orders and suspension of Load Balancing Provisions.

Cumulative Imbalance Charges:

Customers may trade Cumulative Imbalances within a delivery area. Customers may also nominate to transfer gas from their Cumulative Imbalance Account into an unbundled (Rate 315 or Rate 316) storage account of the customer subject to their storage contract parameters.

Customers shall be permitted to nominate Make-up Gas, subject to operating constraints, provided that Make-up Gas plus Aggregate Delivery do not exceed the Contract Demand. The Company may, on days with no operating constraints, authorize Make-up Gas that, in conjunction with Aggregate Delivery, exceeds the Contract Demand.

The customer’s Cumulative Imbalance cannot exceed its Maximum Contractual Imbalance. In the event that the customer's imbalance exceeds their Maximum Contractual Imbalance the Company shall deem the excess imbalance to be Unauthorized Supply Overrun or Underrun gas, as appropriate.

The Cumulative Imbalance Fee, applicable daily, is 1.066 cents/m3 per unit of imbalance.

In addition, on any day that the Company declares an Operational Flow Order, negative Cumulative Imbalances greater than 10 % of Maximum Contractual Imbalance in the winter season shall be deemed to be Unauthorized Overrun Gas. The Company reserves the right to deem positive Cumulative Imbalances greater than 10% of Maximum Contractual Imbalance in the summer season as Unauthorized Supply Underun Gas. The Company will issue a 24-hour advance notice to customers of Operational Flow Orders including cash out instructions for Cumulative Imbalances greater than 10 % of Maximum Contractual Imbalance.

EFFECTIVE DATE:

To apply to bills rendered for gas delivered on and after January 1, 2011. This rate schedule is effective January 1, 2011 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2010 and that indicates as the Board Order, EB-2010-0258 effective October 1, 2010.

APPLICABILITY:

To any Applicant who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation, to a single terminal location ("Terminal Location"), of an annual supply of natural gas of not less than 340,000 cubic metres.

CHARACTER OF SERVICE:

Service shall be continuous (firm) except for events as specified in the Service Contract including force majeure. A maximum of five percent of the contracted annual volume may be taken by the Applicant in a single month during the months of December to March inclusively.

RATE:

Rates per cubic metre assume an energy content of 37.69 MJ/m³.

	Billing Month	
	December to March	**April to November**
Monthly Customer Charge	**$115.08**	**$115.08**
Delivery Charge		
For the first 14,000 m³ per month	**6.7618 ¢/m³**	**2.0618 ¢/m³**
For the next 28,000 m³ per month	**5.5618 ¢/m³**	**1.3618 ¢/m³**
For all over 42,000 m³ per month	**5.1618 ¢/m³**	**1.1618 ¢/m³**
Gas Supply Load Balancing Charge	**0.0000 ¢/m³**	**0.0000 ¢/m³**
Transportation Charge per cubic metre	**4.8217 ¢/m³**	**4.8217 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**15.4256 ¢/m³**	**15.4256 ¢/m³**

The rates quoted above shall be subject to the Gas Cost Adjustment contained in Rider “C” and the Revenue Adjustment Rider contained in Rider "E". In addition, meter readings will be adjusted by the Atmospheric Pressure Factor relevant to the customer’s location as shown in Rider "F". The Gas Supply Charge is applicable if the Applicant is not providing its own supply of natural gas for transportation.

DIRECT PURCHASE ARRANGEMENTS:

Rider "A" or Rider "B" shall be applicable to Applicants who enter into Direct Purchase Arrangements under this Rate Schedule.

The applicant has the option of delivering either Option a) a Mean Daily Volume ("MDV") based on 12 months, or Option b) a Modified Mean Daily Volume ("MMDV") based on nine months of deliveries. Authorized Volumes for the months of January, February and March would be zero under option b).

UNAUTHORIZED OVERRUN GAS RATE:

When the Applicant takes Unauthorized Supply Overrun Gas, the Applicant shall purchase such gas at a rate of 150% of the highest price on each day on which an overrun occurred for the calendar month as published in the Gas Daily for the Niagara and Iroquois export points for the CDA and EDA respectively.

Failure to deliver a volume of gas equal to the Mean Daily Volume under Option a) set out in the Service Contract during the months of December to March inclusive may result in the Applicant not being eligible for service under this rate in a subsequent contract period, at the Company's sole discretion.

Failure to deliver a volume of gas equal to the Modified Mean Daily Volume under Option b) set out in the Service Contract during the month of December may result in the Applicant not being eligible for service under this rate in a subsequent contract period, at the Company's sole discretion.

SEASONAL CREDIT:

Rate per cubic metre of Mean Daily Volume from December to March	**$**	**0.77 /m^3**
Rate per cubic metre of Modified Mean Daily Volume for December	**$**	**0.77 /m^3**

SEASONAL OVERRUN CHARGE:

During the months of December through March inclusively, any volume of gas taken in a single month in excess of five percent of the annual contract volume (Seasonal Overrun Monthly Volume) will be subject to Seasonal Overrun Charges in place of both the Delivery and Gas Supply Load Balancing Charges. The Seasonal Overrun Charge applicable for the months of December and March shall be calculated as 2.0 times the sum of the Gas Supply Load Balancing Charge, Transportation Charge and the maximum Delivery Charge. The Seasonal Overrun Charge applicable for the months of January and February shall be calculated as 5.0 times the sum of the Load Balancing Charge, Transportation Charge and the maximum Delivery Charge.

Seasonal Overrun Charges:

December and March	**23.1670 ¢/m^3**
January and February	**57.9175 ¢/m^3**

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency
(See Terms and Conditions of Service): **8.4073 ¢/m^3**

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after January 1, 2011 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2011 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2010 and that indicates as the Board Order, EB-2010-0258, effective October 1, 2010.

RATE NUMBER: **145**	**INTERRUPTIBLE SERVICE**

APPLICABILITY:

To any Applicant who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation of a specified maximum daily volume of natural gas to a single terminal location ("Terminal Location") which can accommodate the total interruption of gas service as ordered by the Company exercising its sole discretion. The Company reserves the right to satisfy itself that the customer can accommodate the interruption of gas through either a shutdown of operations or a demonstrated ability and readiness to switch to an alternative fuel source. Any Applicant for service under this rate schedule must agree to transport a minimum annual volume of 340,000 cubic metres.

CHARACTER OF SERVICE:

In addition to events as specified in the Service Contract including force majeure, service shall be subject to curtailment or discontinuance upon the Company issuing a notice not less than 16 hours prior to the time at which such curtailment or discontinuance is to commence. An Applicant may, by contract, agree to accept a shorter notice period.

RATE:

Rates per cubic metre assume an energy content of 37.69 MJ/m³.

	Billing Month **January to December**
Monthly Customer Charge	**$123.34**
Delivery Charge	
Per cubic metre of Firm Contract Demand	**8.2300 ¢/m³**
For the first 14,000 m³ per month	**2.8458 ¢/m³**
For the next 28,000 m³ per month	**1.4868 ¢/m³**
For all over 42,000 m³ per month	**0.9278 ¢/m³**
Gas Supply Load Balancing Charge	**0.3785 ¢/m³**
Transportation Charge per cubic metre	**4.8217 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**15.5100 ¢/m³**

The rates quoted above shall be subject to the Gas Cost Adjustment contained in Rider “C” and the Revenue Adjustment Rider contained in Rider "E". In addition, meter readings will be adjusted by the Atmospheric Pressure Factor relevant to the customer’s location as shown in Rider "F". The Gas Supply Charge is applicable if the Applicant is not providing its own supply of natural gas for transportation.

DIRECT PURCHASE ARRANGEMENTS:

Rider "A" or Rider "B" shall be applicable to Applicants who enter into Direct Purchase Arrangements under this Rate Schedule.

CURTAILMENT CREDIT:

Rate for 16 hours of notice per cubic metre of Mean Daily Volume from December to March **$ 0.50 /m³**

In addition, if the Applicant is supplying its own gas requirements, the gas delivered by the Applicant during the period of curtailment shall be purchased by the Company for the Company's use. The purchase price for such gas will be equal to the price that is reported for the month, in the first issue of the Natural Gas *Market Report* published by Canadian Enerdata Ltd. during the month, as the "current" "Avg." (i.e., average) "Alberta One-Month Firm Spot Price" for "AECO 'C' and Nova Inventory Transfer" in the table entitled "Domestic spot gas prices", adjusted for AECO to Empress transportation tolls and compressor fuel costs.

For the areas specified in Appendix A to this Rate Schedule, the Company's gas distribution network does not have sufficient physical capacity under current operating conditions to accommodate the provision of firm service to existing interruptible locations.

UNAUTHORIZED OVERRUN GAS RATE:

When the Applicant takes Unauthorized Supply Overrun Gas, the Applicant shall purchase such gas at a rate of 150% of the highest price on each day on which an overrun occurred for the calendar month as published in the Gas Daily for the Niagara and Iroquois export points for the CDA and EDA respectively.

Any material instance of failure to curtail in any contract year may result in the Applicant forfeiting the right to be served under this rate schedule.

In such case, service hereunder would cease, notwithstanding any Service Contract between the Company and the Applicant. Gas supply and/or transportation service would continue to be available to the Applicant pursuant to the provisions of the Company's Rate 6 until a Service Contract pursuant to another applicable Rate Schedule was executed.

Any Applicant taking a material volume of Unauthorized Supply Overrun Gas, during a period of ordered curtailment, may forfeit its curtailment credits for the respective winter season, December through March inclusive.

On the second and subsequent occasion in a contract year when the Applicant takes Unauthorized Demand Overrun Gas, a new Contract Demand will be established and shall be charged equal to 120% of the applicable monthly charge for twelve months of the current contract term, including retroactively based on the terms of the Service Contract.

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency (See Terms and Conditions of Service):	**8.0031 ¢/m³**

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after January 1, 2011 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2011 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2010 and that indicates as the Board Order, EB-2010-0258, effective October 1, 2010.

APPLICABILITY:

To any Applicant who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation of a specified maximum daily volume of natural gas of not less than 30,000 cubic metres and a minimum annual volume of 5,000,000 cubic metres to a single terminal location ("Terminal Location") which can accommodate the total interruption of gas service when required by the Company. The Company reserves the right to satisfy itself that the customer can accommodate the interruption of gas through either a shutdown of operations or a demonstrated ability and readiness to switch to an alternative fuel source.
The Company, exercising its sole discretion, may order interruption of gas service upon not less than four (4) hours notice.

CHARACTER OF SERVICE:

In addition to events as specified in the Service Contract including force majeure, service shall be subject to curtailment or discontinuance upon the Company issuing a notice not less than 4 hours prior to the time at which such curtailment or discontinuance is to commence.

RATE:

Rates per cubic metre assume an energy content of 37.69 MJ/m³.

	Billing Month **January to December**
Monthly Customer Charge	**$279.31**
Delivery Charge	
Per cubic metre of Contract Demand	**4.0900 ¢/m³**
Per cubic metre of gas delivered	
For the first 1,000,000 m³ per month	**0.5244 ¢/m³**
For all over 1,000,000 m³ per month	**0.3244 ¢/m³**
Gas Supply Load Balancing Charge	**0.2105 ¢/m³**
Transportation Charge per cubic metre	**4.8217 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**15.3448 ¢/m³**

The rates quoted above shall be subject to the Gas Cost Adjustment contained in Rider “C” and the Revenue Adjustment Rider contained in Rider "E". In addition, meter readings will be adjusted by the Atmospheric Pressure Factor relevant to the customer’s location as shown in Rider "F". The Gas Supply Charge is applicable if the Applicant is not providing its own supply of natural gas for transportation.

DIRECT PURCHASE ARRANGEMENTS:

Rider "A" or Rider "B" shall be applicable to Applicants who enter into Direct Purchase Arrangements under this Rate Schedule.

CURTAILMENT CREDIT:

Rate for 4 hours of notice per cubic metre of Mean Daily Volume from December to March **$ 1.10 /m³**

In addition, if the Applicant is supplying its own gas requirements, the gas delivered by the Applicant during the period of curtailment shall be purchased by the Company for the Company's use. The purchase price for such gas will be equal to the price that is reported for the month, in the first issue of the Natural Gas *Market Report* published by Canadian Enerdata Ltd. during the month, as the "current" "Avg." (i.e., average) "Alberta One-Month Firm Spot Price" for "AECO 'C' and Nova Inventory Transfer" in the table entitled "Domestic spot gas prices", adjusted for AECO to Empress transportation tolls and compressor fuel costs.

For the areas specified in Appendix A to this Rate Schedule, the Company's gas distribution network does not have sufficient physical capacity under current operating conditions to accommodate the provision of firm service to existing interruptible locations.

UNAUTHORIZED OVERRUN GAS RATE:

When the Applicant takes Unauthorized Supply Overrun Gas, the Applicant shall purchase such gas at a rate of 150% of the highest price on each day on which an overrun occurred for the calendar month as published in the Gas Daily for the Niagara and Iroquois export points for the CDA and EDA respectively.

Any material instance of failure to curtail in any contract year may result in the Applicant forfeiting the right to be served under this rate schedule.

In such case, service hereunder would cease, notwithstanding any Service Contract between the Company and the Applicant. Gas supply and/or transportation service would continue to be available to the Applicant pursuant to the provisions of the Company's Rate 6 until a Service Contract pursuant to another applicable Rate Schedule was executed.

Any Applicant taking a material volume of Unauthorized Supply Overrun Gas, during a period of ordered curtailment, may forfeit its curtailment credits for the respective winter season, December through March inclusive.

On the second and subsequent occasion in a contract year when the Applicant takes Unauthorized Demand Overrun Gas, a new Contract Demand will be established and shall be charged equal to 120% of the applicable monthly charge for twelve months of the current contract term, including retroactively based on the terms of the Service Contract.

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency (See Terms and Conditions of Service):	**5.5137 ¢/m³**

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after January 1, 2011 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2011 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2010 and that indicates as the Board Order, EB-2010-0258, effective October 1, 2010.

APPLICABILITY:

To any Distributor who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation of an annual supply of natural gas to customers outside of the Company's franchise area.

CHARACTER OF SERVICE:

Service shall be continuous (firm), except for events as specified in the Service Contract including force majeure, up to the contracted firm daily demand and subject to curtailment or discontinuance, of demand in excess of the firm contract demand, upon the Company issuing a notice not less than 4 hours prior to the time at which such curtailment or discontinuance is to commence.

RATE:

Rates per cubic metre assume an energy content of 37.69 MJ/m³.

	Billing Month January to December
Monthly Customer Charge	
The monthly customer charge shall be negotiated with the applicant and shall not exceed:	**$2,000.00**
Delivery Charge	
Per cubic metre of Firm Contract Demand	**14.7000 ¢/m³**
Per cubic metre of gas delivered	**1.1293 ¢/m³**
Gas Supply Load Balancing Charge	**0.5403 ¢/m³**
Transportation Charge per cubic metre	**4.8217 ¢/m³**
System Sales Gas Supply Charge per cubic metre (If applicable)	**15.3448 ¢/m³**
Buy/Sell Sales Gas Supply Charge per cubic metre (If applicable)	**15.3224 ¢/m³**

The rates quoted above shall be subject to the Gas Inventory Adjustment contained in Rider "C" and the Revenue Adjustment Rider contained in Rider "E". Also, meter readings will be adjusted by the Atmospheric Pressure Factor relevant to the customer's location as shown in Rider "F". The Gas Supply Charge is applicable to volumes of natural gas purchased from the Company. The volumes purchased shall be the volumes delivered at the Point of Delivery less any volumes, which the Company does not own and are received at the Point of Acceptance for delivery to the Applicant at the Point of Delivery.

DIRECT PURCHASE ARRANGEMENTS:

Rider "A" or Rider "B" shall be applicable to Applicants who enter into Direct Purchase Arrangements under this Rate Schedule.

CURTAILMENT CREDIT:

Rate for 4 hours of notice per cubic metre of Mean Daily Volume from December to March **$ 1.10 /m³**

In addition, if the Applicant is supplying its own gas requirements, the gas delivered by the Applicant during the period of curtailment shall be purchased by the Company for the Company's use. The purchase price for such gas will be equal to the price that is reported for the month, in the first issue of the Natural Gas *Market Report* published by Canadian Enerdata Ltd. during the month, as the "current" "Avg." (i.e., average) "Alberta One-Month Firm Spot Price" for "AECO 'C' and Nova Inventory Transfer" in the table entitled "Domestic spot gas prices", adjusted for AECO to Empress transportation tolls and compressor fuel costs.

For the areas specified in Appendix A to this Rate Schedule, the Company's gas distribution network does not have sufficient physical capacity under current operating conditions to accommodate the provision of firm service to existing interruptible locations.

UNAUTHORIZED OVERRUN GAS RATE:

When the Applicant takes Unauthorized Supply Overrun Gas, the Applicant shall purchase such gas at a rate of 150% of the highest price on each day on which an overrun occurred for the calendar month as published in the Gas Daily for the Niagara and Iroquois export points for the CDA and EDA respectively.

On the second and subsequent occasion in a contract year when the Applicant takes Unauthorized Demand Overrun Gas, a new Contract Demand will be established and shall be charged equal to 120% of the applicable monthly charge for twelve months of the current contract term, including retroactively based on the terms of the Service Contract.

The third instance of such failure in any contract year may result in the Applicant orfeiting the right to be served under this Rate Schedule. In such case, service hereunder would cease, notwithstanding any Service Contract between the Company and the Applicant. Gas supply and/or transportation service would continue to be available to the Applicant pursuant to the provisions of the Company's Rate 6 until a Service Contract pursuant to another applicable Rate Schedule was executed.

MINIMUM BILL:

Per cubic metre of Annual Volume Deficiency (See Terms and Conditions of Service):	**6.4484 ¢/m³**

TERMS AND CONDITIONS OF SERVICE:

The provisions of PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** apply, as contemplated therein, to service under this Rate Schedule.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after January 1, 2011 under Sales Service including Buy/Sell Arrangements and Transportation Service. This rate schedule is effective January 1, 2011 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2010 and that indicates as the Board Order, EB-2010-0258, effective October 1, 2010.

APPLICABILITY:

To any Applicant who enters into a Service Contract with the Company to use the Company's natural gas distribution network for the transportation to a single Terminal Location of a specified maximum daily volume of natural gas. The Company reserves the right to limit service under this schedule to customers whose maximum contract demand does not exceed 600,000 m3. The Service under this rate requires Automatic Meter Reading (AMR) capability. Service under this schedule is firm unless a customer is currently served under interruptible distribution service or the Company, in its sole judgment, determines that existing delivery facilities cannot adequately serve the load on a firm basis.

The unitized Monthly Contract Demand Charge is also applicable to volumes delivered to any Applicant taking service under a Curtailment Delivered Supply contract with the Company. The unitized rate equals the applicable Monthly Contract Demand Charge times 12/365.

CHARACTER OF SERVICE:

The Service shall be continuous (firm) except for events specified in the Service Contract including force majeure. The Applicant is neither allowed to take a daily quantity of gas greater than the Contract Demand nor an hourly amount in excess of the Contract Demand divided by 24, without the Company's prior consent. Interruptible Distribution Service is provided on a best efforts basis subject to the events identified in the service contract including force majeure and, in addition, shall be subject to curtailment or discontinuance of service when the Company notifies the customer under normal circumstances 4 hours prior to the time that service is subject to curtailment or discontinuance. Under emergency conditions, the Company may curtail or discontinue service on one-hour notice. The Interruptible Service Customer is not allowed to exceed maximum hourly flow requirements as specified in Service Contract.

DISTRIBUTION RATES:

Monthly Customer Charge	**$500.00**
Monthly Contract Demand Charge Firm	**24.9253 ¢/m³**
Interruptible Service:	
Minimum Delivery Charge	**0.3582 ¢/m³**
Maximum Delivery Charge	**0.9834 ¢/m³**
Direct Purchase Administration Charge	**$75.00**
Forecast Unaccounted For Gas Percentage	**0.3%**

Monthly Minimum Bill: The Monthly Customer Charge plus the Monthly Contract Demand Charge.

TERMS AND CONDITIONS OF SERVICE:

1. To the extent that this Rate Schedule does not specifically address matters set out in PARTS III and IV of the Company's **HANDBOOK OF RATES AND DISTRIBUTION SERVICES** then the provisions in those Parts shall apply, as contemplated therein, to service under this Rate Schedule.

2. **Unaccounted for Gas (UFG) Adjustment Factor**:

   The Applicant is required to deliver to the Company on a daily basis the sum of: (a) the volume of gas to be delivered to the Applicant's Terminal Location; and (b) a volume of gas equal to the forecast unaccounted for gas percentage as stated above multiplied by (a).

3. **Nominations**:

   Customer shall nominate gas delivery daily based on the gross commodity delivery required to serve the customer's daily load plus the UFG, net of No-Notice Storage Service provisions under Rate 315, if applicable. The amount of gas delivered under No-Notice Storage Service will also be reduced by the UFG adjustment factor for delivery to the customer's meter.

   Customers may change daily nominations based on the nomination windows within a day as defined by the customer contract with TransCanada PipeLines (TCPL) or Union Gas Limited.

   Schedule of nominations under Rate 300 has to match upstream nominations. This rate does not allow for any more flexibility than exists upstream of the EGD gas distribution system. Where the customer's nomination does not match the confirmed upstream nomination, the nomination will be confirmed at the upstream value.

Customer may nominate gas to a contractually specified Primary Delivery Area that may be EGD's Central Delivery Area (CDA) or EGD's Eastern Delivery Area (EDA) *or* other Delivery Area as specified in the applicable Service Contract. The Company may accept deliveries at a Secondary Delivery Area such as Dawn, at its sole discretion. Quantities of gas nominated to the system cannot exceed Contract Demand, unless Make-up Gas or Authorized Overrun is permitted.

Customers with multiple Rate 300 contracts within a Primary Delivery Area may combine nominations subject to system operating requirements and subject to the Contract Demand for each Terminal Location. For combined nominations the customer shall specify the quantity of gas to each Terminal Location and the order in which gas is to be delivered to each Terminal Location. The specified order of deliveries shall be used to administer Load Balancing Provisions to each Terminal Location. When system conditions require delivery to a single Terminal Location only, nominations with different Terminal Locations may not be combined.

4. **Authorized Demand Overrun:**

The Company may, at its sole discretion, authorize consumption of gas in excess of the Contract Demand for limited periods within a month, provided local distribution facilities have sufficient capacity to accommodate higher demand. In such circumstances, customer shall nominate gas delivery based on the gross commodity delivery required to serve the customer's daily load, including quantities of gas in excess of the Contract Demand, plus the UFG. The Load Balancing Provisions and/or No-Notice Storage Service provisions under Rate 315 cannot be used for Authorized Demand Overrun. Failure to nominate gas deliveries to match Authorized Demand Overrun shall constitute Unauthorized Supply Overrun.

The rate applicable to Authorized Demand Overrun shall equal the applicable Monthly Demand Charge times 12/365 provided, however, that such service shall not exceed 5 days in any contract year. Requests beyond 5 days will constitute a request for a new Contract Demand level, with retroactive charges based on terms of Service Contract.

5. **Unauthorized Demand Overrun:**

Any gas consumed in excess of the Contract Demand and/or maximum hourly flow requirements, if not authorized, will be deemed to be Unauthorized Demand Overrun gas. Unauthorized Demand Overrun gas will establish a new Contract Demand and shall be subject to a charge equal to 120 % of the applicable monthly charge for twelve months of the current contract term, including retroactively based on terms of Service Contract. Unauthorized Demand Overrun gas shall also be subject to Unauthorized Supply Overrun provisions. Where a customer receives interruptible service hereunder and consumes gas during a period of interruption, such gas shall be deemed Unauthorized Supply Overrun. In addition to charges for Unauthorized Supply Overrun, interruptible customers consuming gas during a scheduled interruption shall pay a penalty charge of $18.00 per m3.

6. **Unauthorized Supply Overrun:**

Any volume of gas taken by the Applicant on a day at the Terminal Location which exceeds the sum of:

i. any applicable Load Balancing Provision pursuant to Rate 300 and/or provisions of Rate 315, plus

ii. the volume of gas delivered by the Applicant on that day shall constitute Unauthorized Supply Overrun Gas.

The Company may also deem volumes of gas to be Unauthorized Supply Overrun gas in other circumstances, as set out in the Load Balancing Provisions of Rate 300.

Any gas deemed to be Unauthorized Overrun gas shall be purchased by the customer at a price (Pe), which is equal to 150% of the highest price in effect for that day as defined below*.

7. **Unauthorized Supply Underrun:**

Any volume of gas delivered by the Applicant on any day in excess of the sum of:

i. any applicable Rate 300 Load Balancing Provision pursuant to Rate 300 and/or provisions of Rate 315, plus

ii. the volume of gas taken by the Applicant at the Terminal Location on that day shall be classified as Supply Underrun Gas.

The Company may also deem volumes of gas to be Unauthorized Supply Underrun gas in other circumstances, as set out in the Load Balancing Provisions of Rate 300.

Any gas deemed to be Unauthorized Supply Underrun Gas shall be purchased by the Company at a price (P_u) which is equal to fifty percent (50%) of the lowest price in effect for that day as defined below**.

* where the price P_e expressed in cents / cubic metre is defined as follows:
$P_e = (P_m * E_r * 100 * 0.03769 / 1.055056) * 1.5$

P_m = highest daily price in U.S. $/mmBtu published in the Gas Daily, a Platts Publication, for that day under the column "Absolute", for the Niagara export point if the terminal location is in the CDA delivery area, and the Iroquois export point if the terminal location is in the EDA delivery area.

E_r = Noon day spot exchange rate expressed in Canadian dollars per U.S. dollar for such day quoted by the Bank of Canada in the following days Globe & Mail Publication.

1.055056 = Conversion factor from mmBtu to GJ.

0.03769 = Conversion factor from GJ to cubic metres.

** where the price P_u expressed in cents / cubic metre is defined as follows:
$P_u = (P_l * E_r * 100 * 0.03769 / 1.055056) * 0.5$

P_l = lowest daily price in U.S. $/mmBtu published in the Gas Daily, a Platts Publication, for that day under the column "Absolute", for the Niagara export point if the terminal location is in the CDA delivery area, and the Iroquois export point if the terminal location is in the EDA delivery area.

Term of Contract:

A minimum of one year. A longer-term contract may be required if incremental assets/facilities have been procured/built for the customer. Migration from an unbundled rate to bundled rate may be restricted subject to availability of adequate transportation and storage assets.

Right to Terminate Service:

The Company reserves the right to terminate service to customers served hereunder where the customer’s failure to comply with the parameters of this rate schedule, including interruptible service and load balancing provisions, jeopardizes either the safety or reliability of the gas system. The Company shall provide notice to the customer of such termination; however, no notice is required to alleviate emergency conditions.

Load Balancing:

Any difference between actual daily-metered consumption and the actual daily volume of gas delivered to the system less the UFG shall first be provided under the provisions of Rate 315 - Gas Storage Service, if applicable. Any remaining difference will be subject to the Load Balancing Provisions.

LOAD BALANCING PROVISIONS:

Load Balancing Provisions shall apply at the customer's Terminal Location.

In the event of an imbalance any excess delivery above the customer's actual consumption or delivery less than the actual consumption shall be subject to the Load Balancing Provisions.

Definitions:

Aggregate Delivery:

The Aggregate Delivery for a customer's account shall equal the sum of the confirmed nominations of the customer for delivery of gas to the applicable delivery area from all pipeline sources plus, where applicable, the confirmed nominations of the customer for Storage Service under Rate 316 or Rate 315 and any available No-Notice Storage Service under Rate 315 for delivery of gas to the Applicable Delivery Area.

Applicable Delivery Area:

The Applicable Delivery Area for each customer shall be specified by contract as a Primary Delivery Area. Where system-operating conditions permit, the Company, in its sole discretion, may accept a Secondary Delivery Area as the Applicable Delivery Area by confirming the customer's nomination of such area. Confirmation of a Secondary Delivery Area for a period of a gas day shall cause such area to become the Applicable Delivery Area for such day. Where delivery occurs at both a Terminal Location and a Secondary Delivery Area on a given day, the sum of the confirmed deliveries may not exceed Contract Demand, unless Demand Overrun and/or Make-up Gas is authorized.

Primary Delivery Area:

The Primary Delivery Area shall be delivery area such as EGD's Central Delivery Area (CDA) or EGD's Eastern Delivery Area (EDA), or other Delivery Area as specified in the applicable Service Contract.

Secondary Delivery Area:

A Secondary Delivery Area may be a delivery area such as Dawn where the Company, at its sole discretion, determines that operating conditions permit gas deliveries for a customer.

Actual Consumption:

The Actual Consumption of the customer shall be the metered quantity of gas consumed at the customer's premise.

Net Available Delivery:

The Net Available Delivery shall equal the Aggregate Delivery times one minus the annually determined percentage of Unaccounted for Gas (UFG) as reported by the Company.

Daily Imbalance:

The Daily Imbalance shall be the absolute value of the difference between Actual Consumption and Net Available Delivery.

Cumulative Imbalance:

The Cumulative Imbalance shall be the sum of the difference between Actual Consumption and Net Available Delivery.

Maximum Contractual Imbalance:

The Maximum Contractual Imbalance shall be equal to 60% of the customer's Contract Demand.

Winter and Summer Seasons:

The winter season shall commence on the date that the Company provides notice of the start of the winter period and conclude on the date that the Company provides notice of the end of the winter period. The summer season shall constitute all other days. The Company shall provide advance notice to the customer of the start and end of the winter season as soon as reasonably possible, but in no event not less than 2 days prior to the start or end.

Operational Flow Order:

An Operational Flow Order (OFO) shall constitute an issuance of instructions to protect the operational capacity and integrity of the Company's system, including distribution and/or storage assets, and/or connected transmission pipelines.

Enbridge Gas Distribution, acting reasonably, may call for an OFO in the following circumstances:

- Capacity constraint on the system, or portions of the system, or upstream systems, that are fully utilized;
- Conditions where the potential exists that forecasted system demand plus reserves for short notice services provided by the Company and allowances for power generation customers' balancing requirements would exceed facility capabilities and/or provisions of 3rd party contracts;
- Pressures on the system or specific portions of the system are too high or too low for safe operations;
- Storage system constraints on capacity or pressure or caused by equipment problems resulting in limited ability to inject or withdraw from storage;
- Pipeline equipment failures and/or damage that prohibits the flow of gas;
- Any and all other circumstances where the potential for system failure exists.

Daily Balancing Fee:

On any day where the customer has a Daily Imbalance the customer shall pay a Daily Balancing Fee equal to:

(Tier 1 Quantity X Tier 1 Fee) + (Tier 2 Quantity X Tier 2 Fee) + (Applicable Penalty Fee for Imbalance in excess of the Maximum Contractual Imbalance X the amount of Daily Imbalance in excess of the Maximum Contractual Imbalance)

Where Tier 1 and 2 Fees and Quantities are set forth as follows:

Tier 1 = Daily Imbalance of greater than 2% but less than 10% of the Maximum Contractual Imbalance and shall be subject to a charge of 0.7255 cents/M3

Tier 2 = Daily Imbalance of greater than 10% but less than Maximum Contractual Imbalance shall be subject to a charge of 0.8706 cents/m3

The customers shall also pay any Limited Balancing Agreement (LBA) charges imposed by the pipeline on days when the customer has a Daily Imbalance provided such imbalance matches the direction of the pipeline imbalance. LBA charges shall first be allocated to customers served under Rate 125 and 300. The system bears a portion of these charges only to the extent that the system incurs such charges based on its operation excluding the operation of customers under Rates 125 and 300. In that event, LBA charges shall be prorated based on the relative imbalances.

A Daily Imbalance in excess of the Maximum Contractual Imbalance shall be deemed to be Unauthorized Supply Overrun or Underrun gas, as appropriate.

Customer's Actual Consumption cannot exceed Net Available Delivery when the Company issues an Operational Flow Order in the winter. Net nominations must not be less than consumption at the Terminal Location. Any negative Daily Imbalance on a winter Operational Flow Order day shall be deemed to be Unauthorized Supply Overrun. Customer's Net Available Delivery cannot exceed Actual Consumption when the Company issues an Operational Flow Order in the summer. Actual Consumption must not be less than net nomination at the Terminal Location. Any positive Daily Imbalance on a summer Operational Flow Order day shall be deemed to be Unauthorized Supply Underrun.

The Company will waive Daily Balancing Fee and Cumulative Imbalance Charge on the day of an Operational Flow Order if the customer used less gas that the amount the customer delivered to the system during the winter season or the customer used more gas than the amount the customer delivered to the system during the summer season. The Company will issue a 24-hour advance notice to customers of Operational Flow Orders and suspension of Load Balancing Provisions.

Cumulative Imbalance Charges:

Customers may trade Cumulative Imbalances within a delivery area.

Customers shall be permitted to nominate Make-up Gas, subject to operating constraints, provided that Make-up Gas plus Aggregate Delivery do not exceed Contract Demand. The Company may, on days with no operating constraints, authorize Make-up Gas that, in conjunction with Aggregate Delivery, exceeds Contract Demand.

The customer's Cumulative Imbalance cannot exceed its Maximum Contractual Imbalance. The excess imbalance shall be deemed to be Unauthorized Supply Overrun or Underrun gas, as appropriate.

The Cumulative Imbalance Fee, applicable daily, is 0.7009 cents/m3 per unit of imbalance.

The customer's Cumulative Imbalance shall be equal to zero within five (5) days from the last day of the Service Contract.

EFFECTIVE DATE:

To apply to bills rendered for gas delivered on and after January 1, 2011. This rate schedule is effective January 1, 2011 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2010 and that indicates as the Board Order, EB-2010-0258 effective October 1, 2010.

APPLICABILITY:

This rate is available to any customer taking service under Distribution Rates 125 and 300. It requires a Service Contract that identifies the required storage space and deliverability. In addition, the customer shall maintain a positive balance of gas in storage at all times or forfeit the use of Storage Services for Load Balancing and No-Notice Storage Service.

A daily nomination for storage injection and withdrawal except for No-Notice Storage Service, hereunder, which is used automatically for daily Load Balancing, shall also be required.

The maximum hourly injections / withdrawals shall equal 1/24th of the daily Storage Demand. No-Notice Storage Service is available up to the maximum daily withdrawal rights less the nominated withdrawal or the maximum daily injection rights less the nominated injections.

Storage space shall be based on either of two storage allocation methodologies: (customer's average winter demand - customer's average annual demand) x 151, or [(17 x customers's maximum hourly demand) / 0.1] x 0.57. Customers have the option to select from these two storage space allocation methods the one that best suits their requirements.

Maximum deliverability shall be 1.2% of contracted storage space. The customer may inject and withdraw gas based on the quantity of gas in storage and the limitations specified in the Service Contract. Both injection and withdrawal shall be subject to applicable storage ratchets as determined by the Company and posted from time to time.

CHARACTER OF SERVICE:

Service shall be firm when used in conjunction with firm distribution service. Service is interruptible when used in conjunction with interruptible distribution service. All service is subject to contract terms and force majeure.

The service is available on two bases:

(1) Service nominated daily based on the available capacity and gas in storage up to the maximum contracted daily deliverability; and

(2) No-Notice Storage Service for daily Load Balancing consistent with the maximum hourly deliverability.

RATE:

The following rates and charges shall apply in respect to all gas received by the Company from and delivered by the Company to storage on behalf of the Applicant.

Monthly Customer Charge:	**$150.00**
Storage Reservation Charge:	
Monthly Storage Space Demand Charge	**0.0585 ¢/m³**
Monthly Storage Deliverability Demand Charge	**15.2792 ¢/m³**
Injection & Withdrawal Unit Charge:	**0.3500 ¢/m³**

Monthly Minimum Bill: The sum of the Monthly Customer Charge plus Monthly Demand Charges.

FUEL RATIO REQUIREMENT:

The Fuel Ratio per unit of gas injected and withdrawn is 0.35%.

All Storage Space and Deliverability/Injection Demand Charges are applicable monthly. Injection and withdrawal charges are applicable to each unit of gas injected or withdrawn based on daily nominations and No-Notice Storage Service quantities.

All deemed withdrawal quantities under the No-Notice Storage Service provisions of this rate will be adjusted for the UFG provisions applicable to the distribution service rates.

In addition, for each unit of injection or withdrawal there will be an applicable fuel charge adjustment expressed as a percent of gas.

TERMS AND CONDITIONS OF SERVICE:

1. **Nominated Storage Service**:

Nominations under this rate shall only be accepted at the standard North American Energy Standards Board ("NAESB") nomination windows. The customer may elect to nominate all or a portion of the available withdrawal capacity for delivery to the applicable Primary Delivery Area, which may be EGD's Central Delivery Area (CDA) or EGD's Eastern Delivery Area (EDA). All volumes nominated from storage are delivered first for purposes of daily Load Balancing of available supply assets. When system conditions permit, the customer may nominate all or a portion of the available withdrawal capacity for delivery to Dawn or to the customer's Primary Delivery Area for purposes other than consumption at the customer's own meter.

Storage not nominated for delivery will be available for No-Notice Storage Service. The sum of gas nominated for storage injection and for the Terminal Location shall not exceed the customer's Contract Demand (CD).

The customer may also nominate gas for delivery into storage by nominating the storage delivery area as the Primary Delivery Area. Gas nominated for storage delivery will not be available for No-Notice Storage Service. The sum of gas nominated for storage injection and for the Terminal Location shall not exceed the customer's CD.
Any gas in excess of the contract demand will be subject to cash out as injection overrun gas.

The Company reserves the right to limit injection and withdrawal rights to all storage customers in certain situations, such as major maintenance or construction projects, and may reduce nominations for injections and withdrawals over and above applicable storage ratchets. The Company will provide customers with one week's notice of its intent to limit injection and withdrawal rights, and at the same time, shall provide its best estimate of the duration and extent of the limitations.

In situations where the Company limits injection and withdrawal rights, the Company shall proportionately reduce the Storage Deliverability/Injection Demand Charge for affected customers based on the number of days the limitation is in effect and the difference between Deliverability/Injection Demand, subject to applicable storage ratchets, and the quantity of gas actually delivered or injected.

2. **No-Notice Storage Service**:

The Company, at its sole discretion based on operating conditions, may provide a No-Notice Storage Service that allows customers taking gas under distribution service rates to balance daily deliveries using this Storage Service. No-Notice Storage Service requires that the customer grant the Company the exclusive right to use unscheduled service available from storage to reduce the daily imbalance associated with the actual consumption of the customer.

No-Notice Storage Service is limited to the available, unscheduled withdrawal or injection capacity under contract to serve a customer. Where the customer serves multiple delivery locations from a single storage Service Contract, the customer shall specify the order in which gas is to be delivered to each Terminal Location served under a distribution Service Contract. The specified order of deliveries shall be used to administer Load Balancing Provisions to each Terminal Location.

The availability of No-Notice Storage Service is subject to and reduced by any service schedule from or to storage. To the extent that the quantity of gas available in storage is insufficient to meet the requirements of the customer under a No-Notice Storage Service, the customer will be unable to use the service on a no-notice basis for Load Balancing service. To the extent that the scheduled injections into storage plus No-Notice Storage Service exceed the maximum limit for injection, No-Notice Storage Service will be reduced and the remainder of the gas will constitute a daily imbalance. Gas delivered in excess of the maximum injection quantity shall be deemed injection overrun gas and cashed out at 50% of the lowest index price of gas.

Other provisions:

If the customer elects to use the contracted storage capacity at less than the full volumetric capacity of the storage, the Company may inject its own gas provided that such injection does not reduce the right of the customer to withdraw the full amount of gas injected on any day during the withdrawal season or to schedule its full injection right during the injection season.

Term of Contract:

A minimum of one year.

A longer-term contract may be required if incremental contracts/assets/facilities have been procured/built for the customer.

EFFECTIVE DATE:

To apply to bills rendered for gas delivered on and after January 1, 2011. This rate schedule is effective January 1, 2011 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2010 and that indicates as the Board Order, EB-2010-0258 effective October 1, 2010.

APPLICABILITY:

This rate is available to any customer taking service under Distribution Rates 125 and 300. It requires a Service Contract that identifies the required storage space and deliverability. The customer shall maintain a positive balance of gas in storage at all times. In addition, the customer must arrange for pipeline delivery service from Dawn to the applicable Primary Delivery Area.

This service is not a delivered service and is only available when the relevant pipeline confirms the delivery.

The maximum hourly injections / withdrawals shall equal 1/24th of the daily Storage Demand.

Storage space shall be based on either of two storage allocation methodologies: (customer's average winter demand - customer's average annual demand) x 151, or [(17 x customers's maximum hourly demand) / 0.1] x 0.57. Customers have the option to select from these two storage space allocation methods the one that best suits their requirements.

Maximum deliverability shall be 1.2% of contracted storage space. The customer may inject and withdraw gas based on the quantity of gas in storage and the limitations specified in the Service Contract. Both injection and withdrawal shall be subject to applicable storage ratchets as determined by the Company and posted from time to time.

CHARACTER OF SERVICE:

Service shall be firm when used in conjunction with firm distribution service. Service is interruptible when used in conjunction with interruptible distribution service. All service is subject to contract terms and force majeure.

The service is nominated based on the available capacity and gas in storage up to the maximum contracted daily deliverability.

RATE:

The following rates and charges shall apply in respect to all gas received by the Company from and delivered by the Company to storage on behalf of the Applicant.

Monthly Customer Charge:	**$150.00**
Storage Reservation Charge:	
Monthly Storage Space Demand Charge	**0.0585 ¢/m³**
Monthly Storage Deliverability Demand Charge	**5.2711 ¢/m³**
Injection & Withdrawal Unit Charge:	**0.1074 ¢/m³**

Monthly Minimum Bill: The sum of the Monthly Customer Charge plus Monthly Demand Charges.

FUEL RATIO REQUIREMENT:

The Fuel Ratio per unit of gas injected and withdrawn is 0.35%.

All Storage Space and Deliverability/Injection Demand Charges are applicable monthly. Injection and withdrawal charges are applicable to each unit of gas injected or withdrawn based on daily nominations.

In addition, for each unit of injection or withdrawal there will be an applicable fuel charge adjustment expressed as a percent of gas.

TERMS AND CONDITIONS OF SERVICE:

Nominated Storage Service:

The customer shall nominate storage injections and withdrawals daily. The customer may change daily nominations based on the nomination windows within a day as defined by the customer contract with Union Gas Limited and TransCanada PipeLines (TCPL).

The customer may elect to nominate all or a portion of the available withdrawal capacity for delivery to the applicable Primary Delivery Area.

The Company reserves the right to limit injection and withdrawal rights to all storage customers in certain situations, such as major maintenance or construction projects, and may reduce nominations for injections and withdrawals over and above applicable storage ratchets. The Company will provide customers with one week's notice of its intent to limit injection and withdrawal rights, and at the same time, shall provide its best estimate of the duration and extent of the limitations.

In situations where the Company limits injection and withdrawal rights, the Company shall proportionately reduce the Storage Deliverability/Injection Demand Charge for affected customers based on the number of days the limitation is in effect and the difference between Deliverability/Injection Demand, subject to applicable storage ratchets, and the quantity of gas actually delivered or injected.

The customer may transfer the title of gas in storage.

Other provisions:

If the customer elects to use the contracted storage capacity at less than the full volumetric capacity of the storage, the Company may inject its own gas provided that such injection does not reduce the right of the customer to withdraw the full amount of gas injected on any day during the withdrawal season or to schedule its full injection right during the injection season.

Term of Contract:

A minimum of one year.

A longer-term contract may be required if incremental contracts/assets/facilities have been procured/built for the customer.

EFFECTIVE DATE:

To apply to bills rendered for gas delivered on and after January 1, 2011. This rate schedule is effective January 1, 2011 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2010 and that indicates as the Board Order, EB-2010-0258 effective October 1, 2010.

APPLICABILITY:

To any Applicant whose delivery of natural gas to the Company for transportation to a Terminal Location has been interrupted prior to the delivery of such gas to the Company.

CHARACTER OF SERVICE:

The volume of gas available for backstopping in any day shall be determined by the Company exercising its sole discretion. If the aggregate daily demand for service under this Rate Schedule exceeds the supply available for such day, the available supply shall be allocated to firm service customers on a first requested basis and any balance shall be available to interruptible customers on a first requested basis.

RATE:

The rates applicable in the circumstances contemplated by this Rate Schedule, in lieu of the Gas Supply Charges specified in any of the Company's other Rate Schedules pursuant to which the Applicant is taking service, shall be as follows:

	Billing Month
	January to December
Gas Supply Charge	
Per cubic metre of gas sold	**20.7014 ¢/m³**

provided that if upon the request of an Applicant, the Company quotes a rate to apply to gas which is delivered to the Applicant at a particular Terminal Location on a particular day or days and to which this Rate Schedule is applicable (which rate shall not be less than the Company's avoided cost in the circumstances at the time nor greater than the otherwise applicable rate specified above), then the Gas Supply Charge applicable to such gas shall be the rate quoted by the Company.

EFFECTIVE DATE:

To apply to bills rendered for gas consumed by customers on and after January 1, 2011 under Sales Service and Transportation Service. This rate schedule is effective January 1, 2011 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2010 and that indicates as the Board Order, EB-2010-0258, effective October 1, 2010.

APPLICABILITY AND CHARACTER OF SERVICE:

Service under this rate schedule shall apply to the Transmission and Compression Service Agreement with Union Gas Limited dated April 1, 1989, and the Transmission, Compression and Pool Storage Service Agreement with Centra Gas Ontario Inc. dated May 30, 1994. Service shall be provided subject to the terms and conditions specified in the Service Agreement.

RATE:

The Customer shall pay for service rendered in each month in a contract year, the sum of the following applicable charges:

	Transmission & Compression $\$/10^3m^3$	**Pool Storage $\$/10^3m^3$**
Demand Charge for:		
Annual Turnover Volume	**0.1870**	**0.2253**
Maximum Daily Withdrawal Volume	**16.9047**	**20.4355**
Commodity Charge	**0.9875**	**0.3369**

FUEL RATIO REQUIREMENT:

Fuel Ratio applicable to per unit of gas injected and withdrawn is 0.35%.

MINIMUM BILL:

The minimum monthly bill shall be the sum of the applicable Demand Charges as stated in Rate Section above.

EXCESS VOLUME AND OVERRUN RATES:

In addition to the charges provided for in the Rate Section above, the Customer shall pay, for services rendered, the sum of the following applicable charges as they are incurred:

TERMS AND CONDITIONS OF SERVICE:

1. Excess Volumes will be billed at the total of the Excess Volume Charges as stated above.

2. Transmission and Compression, and Pool Storage Overrun Service will be billed according to the following:
   (a) At the end of each month, in a contract year, the Company will make a determination, for each day in the month, of

      (i) the difference between the volume of gas actually delivered, exclusive of the fuel volume, for Customer's account into the Company System, at the Point of Delivery and the Customer's Maximum Daily Injection Volume, and

      (ii) the difference between the volume of gas actually delivered, exclusive of the fuel volume, for Customer's account from the Company System, at the Point of Delivery, and the Customer's Maximum Daily Withdrawal Volume.

	Excess Volume Charge $/10³m³ / Year	Overrun Charge $/10³m³ / Day
Transmission & Compression		
Authorized	**2.4682**	**0.5558**
Unauthorized	**-**	**223.1420**
Pool Storage		
Authorized	**2.9738**	**0.6719**
Unauthorized	**-**	**269.7482**

(b) For each day of the month, where any such differences exceed 2.0 percent of the Customer's relevant Maximum Daily Injection Volume and/or Maximum Daily Withdrawal Volume, the Customer shall pay a charge equal to the relevant Overrun rates, as stated above, for such differences.

BILLING ADJUSTMENT:

1. Injection deficiency - If at the beginning of any Withdrawal Period the Customer's Storage Balance is less than the Customer's Annual Turnover Volume, due solely to the Company's inability to inject gas for any reason other than the fault of the Customer, then the applicable Demand Charge for Annual Turnover Volume for the contract year beginning the prior April 1 as stated in Rate Section as applicable, shall be adjusted by multiplying each by a fraction, the numerator of which shall be the Customer's Storage Gas Balance as of the beginning of such Withdrawal Period and the denominator shall be the Customer's Annual Turnover Volume as it may have been established for the then current year.

2. Withdrawal deficiency - If in any month in a contract year for any reason other than the fault of the Customer, the Company fails or is unable to deliver during any one or more days, the amount of gas which the Customer has nominated, up to the maximum volumes which the Company is obligated by the Agreement to deliver to the Customer, then the Demand Charge for maximum Contract Daily Withdrawal Volume in the contract year otherwise payable for the month in which such failure occurs, as stated in Rate Section above, as applicable, shall be reduced by an amount for each day of deficiency to be calculated as follows: The Demand Charge for maximum Contract Daily Withdrawal Volume for the contract year for the month will be divided by 30.4 and the result obtained will then be multiplied by a fraction, the numerator being the difference between the nominated volume for such day and the delivered volume for such day and the denominator being the Customer's maximum Contract Daily Withdrawal Volume for such contract year.

TERMS AND EXPRESSIONS:

In the application of this Rate Schedule to each of the Agreements, terms and expressions used in this Rate Schedule have the meanings ascribed thereto in such Agreement.

EFFECTIVE DATE:

To apply to bills rendered for gas delivered on and after January 1, 2011. This rate schedule is effective January 1, 2011 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2010 and that indicates as the Board Order, EB-2010-0258 effective October 1, 2010.

APPLICABILITY:

To any Applicant who enters into a Storage Contract with the Company for delivery by the Applicant to the Company and re-delivery by the Company to the Applicant of a volume of natural gas owned by the Applicant.

CHARACTER OF SERVICE:

Service under this rate is for Full Cycle or Short Cycle storage service; with firm or interruptible injection and withdrawal service, all as may be available from time to time.

RATE:

The following rates and charges shall apply in respect of all gas received by the Company from and re-delivered by the Company to the Applicant.

	Full Cycle		Short Cycle
	Firm	Interruptible	
	$/10³m³	$/10³m³	$/10³m³
Monthly Demand Charge per unit of Annual Turnover Volume:			
Minimum	**0.4123**	**0.4123**	**-**
Maximum	**2.0615**	**2.0615**	**-**
Monthly Demand Charge per unit of Contracted Daily Withdrawal:			
Minimum	**37.3402**	**29.8722**	**-**
Maximum	**186.7010**	**149.3608**	**-**
Commodity Charge per unit of gas delivered to / received from storage:			
Minimum	**1.3244**	**1.3244**	**0.6841**
Maximum	**6.6220**	**6.6220**	**38.6149**

FUEL RATIO REQUIREMENT:

The Fuel Ratio per unit of gas injected and withdrawn is 0.35%.

TRANSACTING IN ENERGY:

The conversion factor is 37.74MJ/m3, which corresponds to Union Gas' System Wide Average Heating Value, as per the Board's RP-1999-0017 Decision with Reasons.

MINIMUM BILL:

The minimum monthly bill shall be the sum of the applicable Demand Charges.

RATE NUMBER: **330**

OVERRUN RATES:

The units rates stated below will apply to overrun volumes. The provision of Authorized Overrun service will be at the Company's sole discretion.

	Full Cycle Firm $/10³m³	Full Cycle Interruptible $/10³m³	Short Cycle $/10³m³
Authorized Overrun Annual Turnover Volume Negotiable, not to exceed:	**38.6149**	**38.6149**	**38.6149**
Authorized Overrun Daily Injection/Withdrawal Negotiable, not to exceed:	**38.6149**	**38.6149**	**38.6149**
Unauthorized Overrun Annual Turnover Volume Excess Storage Balance			
September 1 - November 30	**386.1490**	**386.1490**	**386.1490**
December 1 - October 31	**38.6149**	**38.6149**	**38.6149**
Unauthorized Overrun Annual Turnover Volume Negative Storage Balance			

TERMS AND CONDITIONS OF SERVICE:

1. All Services are available at the Company's sole discretion.

2. Delivery and Re-delivery of the volume of natural gas shall be from/to the facilities of Union Gas Limited and / or TransCanada PipeLines Limited in Dawn Township and/or Niagara Gas Transmission Limited in Moore Township.

3. The Customers daily injections or withdrawals will be adjusted to provide for the fuel ratio stated in the Fuel Ratio Section. In the event that a Short Cycle service does not require fuel for injection and/or withdrawal, the fuel ratio commodity charge may be waived.

EFFECTIVE DATE:

To apply to bills rendered for gas delivered on and after January 1, 2011. This rate schedule is effective January 1, 2011 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2010 and that indicates as the Board Order, EB-2010-0258 effective October 1, 2010.

APPLICABILITY:

To any Applicant who enters into an agreement with the Company pursuant to the Rate 331 Tariff ("Tariff") for transportation service on the Company's pipelines extending from Tecumseh to Dawn ("Tecumseh Pipeline"). The Company will receive gas at Tecumseh and deliver the gas at Dawn. Capitalized terms used in this Rate Schedule shall have the meanings ascribed to those terms in the Tariff.

CHARACTER OF SERVICE:

Transportation service under this Rate Schedule may be available on a firm basis ("FT Service") or an interruptible basis ("IT Service"), subject to the terms and conditions of service set out in the Tariff and the applicable rates set out below.

RATE:

The following rates, effective January 1, 2011, shall apply in respect of FT and IT Service under this Rate Schedule:

	Demand Rate $\$/10^3m^3$	Commodity Rate $\$/10^3m^3$
FT Service	**5.2700**	**-**
IT Service	**-**	**0.2080**

FT Service: The monthly demand charge shall be the products obtained by multiplying the applicable Maximum Daily Volume by the above demand rate.

IT Service: The monthly commodity charge shall be the product obtained by multiplying the applicable Delivery Volume for the Month by the above commodity rate.

TERMS AND CONDITIONS OF SERVICE:

The terms and conditions of FT and IT Service are set out in the Tariff. The provisions of PARTS I to IV of the Company's HANDBOOK OF RATES AND DISTRIBUTION SERVICES do not apply to Rate 331 service.

EFFECTIVE DATE:

The Tariff was approved by the Board in Board Order EB-2010-0177, dated July 12, 2010, and is posted and available on the Company's website. In accordance with Section 1.6.2 of the Board's Storage and Transportation Access Rule, the Tariff does not apply to any Rate 331 service agreements executed prior to June 16, 2010.

Applicants located off the piping networks noted below or off piping systems supplied from these networks may be curtailed to maintain distribution system integrity.

The Town of Collingwood
The Town of Midland

APPLICABILITY:

This rider is applicable to any Applicant who enters into Gas Transportation Agreement with the Company under any rate other than Rates 125 and 300.

MONTHLY DIRECT PURCHASE ADMINISTRATION CHARGE:

Fixed Charge	$75.00	per month
Account Charge	$0.21	per month per account

AVERAGE COST OF TRANSPORTATION:

The average cost of transportation effective January 1, 2011:

Point of Acceptance	Firm Transportation (FT)
CDA, EDA	4.8217 ¢/m³

<u>TCPL FT CAPACITY TURNBACK:</u>

APPLICABILITY:

To Ontario T-Service and Western T-Service customers who have been or will be assigned TCPL capacity by the Company.

TERMS AND CONDITIONS OF SERVICE:

1. The Company will accommodate TCPL FT capacity turnback requests from customers, but only if it can do so in accordance with the following considerations:
   i. The FT capacity to be turned back must be replaced with alternative, contracted firm transportation (primary capacity or assignment) of equivalent quality to the TCPL FT capacity;
   ii. The amount of turnback capacity that Enbridge otherwise may accommodate may be reduced to address the impact of stranded costs, other transitional costs or incremental gas costs resulting from the loss of STS capacity arising from any turnback request; and
   iii. Enbridge must act in a manner that maintains the integrity and reliability of the gas distribution system and that respects the sanctity of contracts.
2. Requests for TCPL FT turnback must be made in writing to the attention of Enbridge's Direct Purchase group.
3. All TCPL FT capacity turnback requests will be treated on an equitable basis.
4. The percentage turnback of TCPL FT capacity will be applied at the Direct Purchase Agreement level.

5. Written notice to turnback capacity must be received by the Company the earlier of:

   (a) Sixty days prior to the expiry date of the current contract.

   or

   (b) A minimum of one week prior to the deadline specified in TransCanada tariff for FT contract extension.

EFFECTIVE DATE:

To apply to bills rendered for gas delivered on and after January 1, 2011. This rate schedule is effective January 1, 2011 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2010 and that indicates as the Board Order, EB-2010-0258 effective October 1, 2010.

RIDER: B	BUY / SELL SERVICE RIDER

APPLICABILITY:

This rider is applicable to any Applicant who entered into a Gas Purchase Agreement with the Company, prior to April 1, 1999, to sell to the Company a supply of natural gas.

MONTHLY DIRECT PURCHASE ADMINISTRATION CHARGE:

Fixed Charge	$75.00	per month
Account Charge	$0.21	per month per account

BUY / SELL PRICE:

In Buy/Sell Arrangements between the Company and an Applicant, the Company shall buy the Applicants gas at the Company's actual FT-WACOG price determined on a monthly basis in the manner approved by the Ontario Energy Board. For Western Buy/Sell arrangements the FT-WACOG price shall be reduced by pipeline transmission costs.

FT FUEL PRICE:

The FT fuel price used to establish the Buy price in Western Buy/Sell arrangements without fuel will be determined monthly based upon the actual FT-WACOG.

EFFECTIVE DATE:

To apply to bills rendered for gas delivered on and after January 1, 2011. This rate schedule is effective January 1, 2011 and replaces the identically numbered rate schedule that specifies implementation date, October 1, 2010 and that indicates as the Board Order, EB-2010-0258 effective October 1, 2010.

RIDER: C	GAS COST ADJUSTMENT RIDER

The following adjustment is applicable to all gas sold or delivered during the period of January 1, 2011 to September 30, 2011.

Rate Class	Sales Service (¢/m³)	Western Transportation Service (¢/m³)	Ontario Transportation Service (¢/m³)
Rate 1	0.0000	0.0000	0.0000
Rate 6	0.0000	0.0000	0.0000
Rate 9	0.0000	0.0000	0.0000
Rate 100	0.0000	0.0000	0.0000
Rate 110	0.0000	0.0000	0.0000
Rate 115	0.0000	0.0000	0.0000
Rate 135	0.0000	0.0000	0.0000
Rate 145	0.0000	0.0000	0.0000
Rate 170	0.0000	0.0000	0.0000
Rate 200	0.0000	0.0000	0.0000

Rate Class		Sales Service (¢/m³)	Western Transportation Service (¢/m³)	Ontario Transportation Service (¢/m³)
Rate 1	Commodity	0.0000		
	Transportation	0.0000	0.0000	
	Load Balancing	0.0000	0.0000	0.0000
	Total	0.0000	0.0000	0.0000
Rate 6	Commodity	0.0000		
	Transportation	0.0000	0.0000	
	Load Balancing	0.0000	0.0000	0.0000
	Total	0.0000	0.0000	0.0000
Rate 9	Commodity	0.0000		
	Transportation	0.0000	0.0000	
	Load Balancing	0.0000	0.0000	0.0000
	Total	0.0000	0.0000	0.0000
Rate 100	Commodity	0.0000		
	Transportation	0.0000	0.0000	
	Load Balancing	0.0000	0.0000	0.0000
	Total	0.0000	0.0000	0.0000
Rate 110	Commodity	0.0000		
	Transportation	0.0000	0.0000	
	Load Balancing	0.0000	0.0000	0.0000
	Total	0.0000	0.0000	0.0000
Rate 115	Commodity	0.0000		
	Transportation	0.0000	0.0000	
	Load Balancing	0.0000	0.0000	0.0000
	Total	0.0000	0.0000	0.0000
Rate 135	Commodity	0.0000		
	Transportation	0.0000	0.0000	
	Load Balancing	0.0000	0.0000	0.0000
	Total	0.0000	0.0000	0.0000

RIDER: **C**

Rate Class		Sales Service (¢/m³)	Western Transportation Service (¢/m³)	Ontario Transportation Service (¢/m³)
Rate 145	Commodity	0.0000		
	Transportation	0.0000	0.0000	
	Load Balancing	0.0000	0.0000	0.0000
	Total	0.0000	0.0000	0.0000
Rate 170	Commodity	0.0000		
	Transportation	0.0000	0.0000	
	Load Balancing	0.0000	0.0000	0.0000
	Total	0.0000	0.0000	0.0000
Rate 200	Commodity	0.0000		
	Transportation	0.0000	0.0000	
	Load Balancing	0.0000	0.0000	0.0000
	Total	0.0000	0.0000	0.0000

Bundled Services Rate Class	Sales Service (¢/m³)	Western Transportation Service (¢/m³)	Ontario Transportation Service (¢/m³)
Rate 1	0.0000	0.0000	0.0000
Rate 6	0.0000	0.0000	0.0000
Rate 9	0.0000	0.0000	0.0000
Rate 100	0.0000	0.0000	0.0000
Rate 110	0.0000	0.0000	0.0000
Rate 115	0.0000	0.0000	0.0000
Rate 135	0.0000	0.0000	0.0000
Rate 145	0.0000	0.0000	0.0000
Rate 170	0.0000	0.0000	0.0000
Rate 200	0.0000	0.0000	0.0000

Unbundled Services Rate Class	Distribution Service (¢/m³)
Rate 125	0.0000
Rate 300	0.0000

RIDER: F	ATMOSPHERIC PRESSURE FACTORS

The following elevation factors shall be applicable to metered volumes measured by a meter that does not correct for atmospheric pressure.

Zone	Elevation Factor
1	0.9644
2	0.9652
3	0.9669
4	0.9678
5	0.9686
6	0.9703
7	0.9728
8	0.9745
9	0.9762
10	0.9771
11	0.9839
12	0.9847
13	0.9856
14	0.9864
15	0.9873
16	0.9881
17	0.9890
18	0.9898
19	0.9907
20	0.9915
21	0.9932
22	0.9941
23	0.9949
24	0.9958
25	0.9960
26	0.9966
27	0.9975
28	0.9981
29	0.9983
30	0.9992
31	0.9997
32	1.0000
33	1.0017
34	1.0025
35	1.0034
36	1.0051
37	1.0059
38	1.0170

	Rate (excluding GST)
New Account Or Activation	
New Account Charge Turning on of gas, activating appliances, obtaining billing data and establishing an opening meter reading for new customers in premises where gas has been previously supplied	$25.00
Appliance Activation Charge - Commercial Customers Only Commercial customers are charged an appliance activation charge on unlock and red unlock orders, except on the very first unlock and service unlock at a premise.	$70.00 minimum 1/2 hour work. Total Amount depends on time required
Meter Unlock Charge - Seasonal or Pool Heater Seasonal for all other revenue classes, or Pool Heater for residential only	$70.00
Statement of Account	
Lawyer Letter Handling Charge Provide the customer's lawyer with gas bill information.	$15.00
Statement of Account Charge (for one year history)	$10.00
Cheques Returned Non-Negotiable Charge	$20.00
Gas Termination	
Red Lock Charge Locking meter or shutting off service by closing the street shut-off valve (when work can be performed by Field Collector)	$70.00
Removal of Meter Removing meter by Construction & Maintenance crew	$280.00
Cut Off At Main Charge Cutting service off at main by Construction & Maintenance Crew	$1,300.00
Valve Lock Charge Shutting off service by closing the street	
shut-off valve - work performed by Field Investigator	$135.00
- work performed by Construction & Maintenance	$280.00

Safety Inspection	
Inspection Charge	$70.00
For inspection of gas appliances; the Company provides only one inspection free of charge, upon first time introduction of gas to a premise.	
Inspection Reject Charge (safety inspection)	$70.00
Energy Board Inspection rejects are billed to the meter installer or homeowner.	
Meter Test	
Meter Test Charge	
When a customer disputes the reading on his/her meter, he/she may request to have the meter tested. This charge will apply if the test result confirms the meter is recording consumption correctly.	
Residential meters	$105.00
Non-Residential meters	Time & Material per Contractor
Street Service Alteration	
Street Service Alteration Charge	$32.00
For installation of service line beyond allowable guidelines (for new residential services only)	
NGV Rental	
NGV Rental Cylinder (weighted average)	$12.00
Other Customer Services (ad-hoc request)	
Labour Hourly Charge-Out Rate	$140.00
Cut Off At Main Charge - Commercial & Special Requests	custom quoted
Cut Off At Main charges for commercial services and other residential services that involve significantly more work than the average will be custom quoted.	
Cut Off At Main Charge - Other Customer Requests	$1,300.00
Other residential Cut Off At Main requests due to demolitions, fires, inactive services, etc. will be charged at the standard COAM rate.	
Meter In-Out (Residential Only))	$280.00
Relocate the meter from inside to outside per customer request	
Request For Service Call Information	$30.00
Provide written information of the result of a service call as requested by home owners.	
Temporary Meter Removal	$280.00
As requested by customers.	
Damage Meter Charge	$380.00

APPLICABILITY:

This rider is applicable to any Applicant who enters into Gas Delivery Agreement with the Company under any rate.

IN FRANCHISE TITLE TRANSFER SERVICE:

In any Gas Delivery Agreement between the Company and the Applicant, an Applicant may elect to initiate a transfer of natural gas from one of its pools to the pool of another Applicant for the purposes of reducing an imbalance between the Applicant's deliveries and consumption as recorded in its Banked Gas Account or Cumulative Imbalance Account. Elections must be made in accordance with the Company's policies and procedures related to transaction requests under the Gas Delivery Agreement.

The Company will not apply an Administration charge for transfers between pools that have similar Points of Acceptance (i.e. both Ontario or both Western Points of Acceptance). For transfers between pools that have dissimilar Points of Acceptance (i.e. one an Ontario and one a Western Point of Acceptance), the Company will apply the following Administration Charge per transaction to the Applicant transferring the natural gas (i.e. the seller or transferor).

Administration Charge:	$169.00	per transaction

Also, the average cost of transportation as per Rider A for the transferred volume is charged to the Applicant with a Western Point of Acceptance for transfers to an Applicant with an Ontario Point of Acceptance. The average cost of transportation as per Rider A for the transferred volume is remitted to the Applicant with a Western Point of Acceptance for transfers from an Applicant with an Ontario Point of Acceptance.

ENHANCED TITLE TRANSFER SERVICE:

In any Gas Delivery Agreement between the Company and the Applicant, the Applicant may elect to initiate a transfer of natural gas between the Company and another utility, regulated by the Ontario Energy Board, at Dawn for the purposes of reducing an imbalance between the customer's deliveries and consumption within the Enbridge Gas Distribution franchise areas. The ability of the Company to accept such an election may be constrained at various points in time for customers obtaining services under any rate other than Rate 125 or 300 due to operational considerations of the Company.

The cost for this service is separated between an Adminstration Charge that is applicable to all Applicants and a Bundled Service Charge that is only applicable to Applicants obtaining services under any rate other than Rate 125 or 300.

Administration Charge:		
Base Charge	$50.00	per transaction
Commodity Charge	$0.6622	per 10^3m^3

Bundled Service Charge:
The Bundled Service Charge shall be equal to the absolute difference between the Eastern Zone and Southwest Zone Firm Transportation tolls approved by the National Energy Board for TCPL at a 100% Load Factor.

Also, the average cost of transportation as per Rider A for the transferred volume is charged to the Applicant with a Western Point of Acceptance for transfers to another party. The average cost of transportation as per Rider A for the transferred volume is remitted to the Applicant with a Western Point of Acceptance for transfers from another party.

GAS IN STORAGE TITLE TRANSFER:

An Applicant that holds a contract for storage services under Rate 315 or 316 may elect to initiate a transfer of title to the natural gas currently held in storage between the storage service and another storage service held by the Applicant, or any other Applicant that has contracted with the Company for storage services under Rate 315 or 316. The service will be provided on a firm basis up to the volume of gas that is equivalent to the more restrictive firm withdrawal and injection parameters of the two parties involved in the transfer. Transfer of title at rates above this level may be done on at the Company's discretion.

For Applicants requesting service between two storage service contracts that have like services, each party to the request shall pay an Administration Charge applicable to the request. Services shall be considered to be alike if the injection and deliverability rate at the ratchet levels in effect at the time of the request are the same and both services are firm or both services are interruptible. In addition to like services, the Company, at its sole discretion based on operational conditions, will also allow for the transfer of gas from a storage service contract that has a level of deliverability that is higher than the level of deliverability of the storage service contract the gas is being transfered to with only the Administration Charge being applicable to each party.

In addition to the Administration Charge, Applicants requesting service between two storage service contracts not addressed in the preceding paragraph would be subject to the injection and withdrawal charges specified in their contracts.

Administration Charge:	$25.00	per transaction

Supporting Documentation
Draft Final Rate Order: EB-2010-0146

DOCUMENTATION FOR WORKING PAPERS SUPPORTING THE DRAFT FINAL RATE ORDER: EB-2010-0146

The attached working papers provide support for the Rate Handbook filed as Appendix B to the Draft Final Rate Order for final 2011 rates effective January 1, 2011. The Rate Handbook reflects the Settlement Agreement dated November 23, 2010 under docket EB-2010-0146.

The final 2011 rates shown in the Rate Handbook are designed to recover the revenues stemming from the EB-2010-0146 Settlement Agreement and incorporate the October 1, 2010 QRAM (EB-2010-0258) rates as the base rates. The October 1, 2010 QRAM rates were the most recent rates approved by the OEB at the time the Company filed its 2011 rates application.

The Company is proposing to implement the final Rate Order on January 1, 2011. The final 2011 rates shown in the Rate Handbook will be immediately superceded by the January 1, 2011 QRAM rates approved under EB-2010-0347.

As outlined in Appendix A, the final 2011 revenue to be recovered in rates equals $2,404.89 million. This includes distribution revenue requirement of $988.59 million and gas costs of $1,416.30 million:

2011 Distribution Revenue Requirement	$ 988.59
2011 Gas Costs to Operations (Oct. 1, 2010 ref. price)	$1,416.30
2011 Total Revenue Requirement	$ 2,404.89

The working papers are laid out as follows:

Exhibit B, Tab 3, Schedules 3-9: Design of Rates
Exhibit B, Tab 3, Schedule 10: Assignment of 2011 Revenue Requirement

Rate design exhibits are filed at Exhibit B, Schedules 3 to 9. The exhibits present the recovery of the final 2011 revenues. The schedules are organized in the following manner:

a) Schedule 3 summarizes, by rate class, and rate component, the revenues at final rates which are forecast to be recovered in 2011.
b) Schedule 4 displays the revenues by rate class and component and by unit rate in conjunction with the associated volumes.
c) Schedule 5 summarizes the revenues shown in Schedule 3 and presents the unbilled revenues at final rates.
d) Schedule 6 compares the base unit rates from EB-2010-0258 (October 1, 2010 QRAM) to the final 2011 unit rates.
e) Schedule 7, pages 1 and 2 show the derivation of gas supply, gas supply load balancing, and transportation rates. Page 3 depicts the generation of the seasonal and interruptible credits.

f) Schedule 8 shows the detailed revenue calculations by rate class.
g) Schedule 9 compares annual bills indicating the impact of the Company's final 2011 rates on typical rate class customer relative to the EB-2010-0258 (October 1, 2010 QRAM) base rates.
h) Schedule 10 assigns the 2011 revenue requirement to the customer rate classes and acts as a guide to rate design.

The average rate impacts stemming from the EB-2010-0146 Settlement Agreement are presented in Table 1 below.

Table 1: 2011 Average Rate Impacts

Rate Class	T-Service Rate Impacts
1	-0.8%
6	-1.5%
9	-0.4%
100	-2.2%
110	-3.6%
115	-4.3%
135	-4.7%
145	-3.6%
170	-5.5%
200	-3.2%
	2011 Delivery Rate Impact
125	0.5%
300	0.5%

Adjustment to Rates from Settlement of Issue 13 (DPAC and System Gas Fee)

The Company had updated the 2011 level of costs which support direct purchase and system gas options consistent with the Board's decision in EB-2008-0106. Updating these costs is revenue neutral for Enbridge as it does not impact the level of revenues derived from the Company's Revenue Cap per Customer Incentive Regulation model, but it is meant to ensure that an appropriate level of costs is recovered through charges related to supporting system gas and direct purchase options rather than through the Company's distribution rates (which are reduced accordingly). The direct purchase charge ("DPAC") recovers the incremental costs incurred to support the direct purchase function and is comprised of a fixed monthly charge per pool and a monthly variable charge per account. The system gas fee recovers the incremental costs incurred to support the system gas function and is a variable unit rate applied to system sales gas volumes. The per unit rate forms part of the Company's system sales gas supply charge.

Based on the updated costs, the Company had proposed to increase the 2011 DPAC account charge per month and System Gas Fee however as outlined in the settlement agreement at Issue 13, an agreement has been reached to maintain the existing 2010 charges for the DPAC charge and System Gas Fee. This has the effect of decreasing the amount of forecast revenue to be recovered from the DPAC charges and System Gas Fee and increasing the amount of revenue being recovered by the distribution rates. The distribution revenue requirement and overall revenue requirement remain unchanged at $988.59 and $2404.9 million respectively.

The 2010 DPAC fixed charge is $75 per pool with a monthly account charge of $0.21 per account. Based on the forecast level of 2011 pools and accounts this generates revenue of approximately $2.662 million. The Company had proposed to design the DPAC charges to recover approximately $2.870 million. Therefore, the impact of the settlement agreement transfers approximately $0.208 million from DPAC revenue to distribution revenue.

The 2010 System gas fee is 0.0224 cents per m3. Based on the forecast level of 2011 system gas volumes, the 2010 system gas fee of 0.0224 cents per m3 generates revenue of approximately $1.311 million. The Company had proposed to design the System Gas Fee to recover approximately $1.379 million. Therefore, the impact of the settlement agreement transfers approximately $0.068 million from System Gas Fee revenue to distribution revenue.

The total change to distribution revenue of $0.276 million ($0.208+$0.068) is recovered from the customer rate classes in the following manner (which roughly follows the allocation of the distribution revenue requirement to the rate classes as shown at Exhibit B, Tab 3, Schedule 10, Page 7, Item 1.6):

Rate Class	Change In Distribution Revenue ($'000)
1	187.67
6	79.34
9	0.06
110	2.29
115	1.09
125	1.89
135	.11
145	1.34
170	1.03
200	.66
300	.16
Total	$275.64

REVENUE REQUIREMENT - PROPOSED METHODOLOGY BY RATE CLASS AND COMPONENT ($000)

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
		REVENUE -EB-2010-0146 RATES				
ITEM NO.	RATE NO.	DISTRIBUTION	TRANSPORT	GAS SUPPLY LOAD BAL	GAS SUPPLY COMMODITY	TOTAL
1.	1	721,953	184,986	33,596	518,734	1,459,269
2.	6	317,389	145,346	29,335	346,983	839,053
3.	9	91	27	0	63	180
4.	100	0	0	0	0	0
5.	110	10,486	9,610	661	9,898	30,655
6.	115	6,372	1,272	242	63	7,949
7.	125	7,292	0	0	0	7,292
8.	135	836	1,390	(422)	93	1,897
9.	145	5,211	4,439	(402)	3,465	12,713
10.	170	4,727	6,119	(5,604)	7,661	12,902
11.	200	3,737	5,965	746	18,982	29,430
12.	300	412	0	0	0	412
13.	SUB-TOTAL	1,078,507	359,154	58,152	905,941	2,401,754
14.	STORAGE	1,601	0	0	0	1,601
15.	DPAC	2,662	0	0	0	2,662
16.	TOTAL	1,082,769	359,154	58,152	905,941	2,406,016

PROPOSED VOLUMES AND REVENUE RECOVERY BY RATE CLASS ($000)

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13
		DISTRIBUTION			GAS SUPPLY TRANSPORTATION			GAS SUPPLY LOAD BALANCING			GAS SUPPLY COMMODITY			TOTAL
ITEM NO.	RATE NO.	VOLUMES	REVENUES	UNIT RATE	VOLUMES	REVENUES	UNIT RATE	VOLUMES	REVENUES	UNIT RATE	VOLUMES	REVENUES	UNIT RATE	REVENUES
		10^3 m^3	$000	¢/m^3	10^3 m^3	$000	¢/m^3	10^3 m^3	$000	¢/m^3	10^3 m^3	$000	¢/m^3	$000
1.	1	4,764,426	721,953	15.15	3,836,515	184,986	4.82	4,764,426	33,596	0.71	3,356,349	518,734	15.46	1,459,269
2.	6	4,518,434	317,389	7.02	3,014,405	145,346	4.82	4,518,434	29,335	0.65	2,235,728	346,983	15.52	839,053
3.	9	558	91	16.21	558	27	4.82	558	0	0.00	408	63	15.34	180
4.	100	0	0	0.00	0	0	0.00	0	0	0.00	0	0	0.00	0
5.	110	471,855	10,486	2.22	199,310	9,610	4.82	471,855	661	0.14	64,501	9,898	15.34	30,655
6.	115	513,097	6,372	1.24	26,383	1,272	4.82	513,097	242	0.05	410	63	15.34	7,949
7.	125	0	7,292	0.00	0	0	0.00	0	0	0.00	0	0	0.00	7,292
8.	135	50,028	836	1.67	28,838	1,390	4.82	50,028	(422)	(0.84)	600	93	15.43	1,897
9.	145	237,331	5,211	2.20	92,073	4,439	4.82	237,331	(402)	(0.17)	22,339	3,465	15.51	12,713
10.	170	563,271	4,727	0.84	126,895	6,119	4.82	563,271	(5,604)	(0.99)	49,927	7,661	15.34	12,902
11.	200	157,393	3,737	2.37	123,704	5,965	4.82	157,393	746	0.47	123,704	18,982	15.34	29,430
12.	300	30,000	412	0.00	0	0	0.00	0	0	0.00	0	0	0.00	412
13	SUB-TOTAL	11,306,393	1,078,507	9.54	7,448,681	359,154	4.8217	11,276,393	58,152	0.52	5,853,968	905,941	15.48	2,401,754
14.	STORAGE	N/A	1,601	N/A	N/A	0	N/A	N/A	0	N/A	N/A	0	N/A	1,601
15.	DPAC	N/A	2,662	N/A	N/A	0	N/A	N/A	0	N/A	N/A	0	N/A	2,662
16.	TOTAL	11,306,393	1,082,769	9.54	7,448,681	359,154	4.82	11,276,393	58,152	0.52	5,853,968	905,941	15.48	2,406,016

REVENUE - PROPOSED METHODOLOGY BY RATE CLASS

	Col. 1	Col. 2	Col. 3	Col. 4
		REVENUE -EB-2010-0146 RATES		
Item No.	Rate No.	Proposed Revenue ($000)	Unbilled Revenue ($000)	Total ($000)
1.	1	1,459,269	(602)	1,458,667
2.	6	839,053	(570)	838,483
3.	9	180	0	180
4.	100	0	0	0
5.	110	30,655	(19)	30,635
6.	115	7,949	4	7,953
7.	125	7,292	0	7,292
8.	135	1,897	(9)	1,888
9.	145	12,713	75	12,788
10.	170	12,902	(2)	12,900
11.	200	29,430	0	29,430
12.	300	412	0	412
13.	SUB-TOTAL	2,401,754	(1,123)	2,400,630
14.	STORAGE	1,601	0	1,601
15.	DPAC	2,662	0	2,662
16.	TOTAL	2,406,016	(1,123)	2,404,893

SUMMARY OF PROPOSED RATE CHANGE BY RATE CLASS

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5
Item No.	Rate No.		Rate Block m³	EB-2010-0258 cents *	Rate Change cents *	EB-2010-0146 cents *
	RATE 1					
1.01		Customer Charge		$18.00	$1.00	$19.00
1.02		Delivery Charge	first 30	7.7315	(0.4255)	7.3060
1.03			next 55	7.2334	(0.3981)	6.8353
1.04			next 85	6.8431	(0.3766)	6.4665
1.05			over 170	6.5525	(0.3606)	6.1919
1.06		Gas Supply Load Balancing		0.6655	0.0397	0.7052
1.07		Gas Supply Transportation		5.1042	(0.2825)	4.8217
1.08		Gas Supply Commodity - System		15.4224	0.0329	15.4553
1.09		Gas Supply Commodity - Buy/Sell		15.4000	0.0329	15.4329
	RATE 6					
2.01		Customer Charge		$60.00	$5.00	$65.00
2.02		Delivery Charge	First 500	7.2015	(0.2431)	6.9584
2.03			Next 1050	5.5052	(0.1858)	5.3193
2.04			Next 4500	4.3176	(0.1457)	4.1719
2.05			Next 7000	3.5543	(0.1200)	3.4343
2.06			Next 15250	3.2152	(0.1085)	3.1066
2.07			Over 28300	3.1302	(0.1057)	3.0246
2.08		Gas Supply Load Balancing		0.6265	0.0227	0.6492
2.09		Gas Supply Transportation		5.1042	(0.2825)	4.8217
2.10		Gas Supply Commodity - System		15.5079	0.0120	15.5199
2.11		Gas Supply Commodity - Buy/Sell		15.4855	0.0120	15.4975
	RATE 9					
3.01		Customer Charge		$233.12	$2.77	$235.89
3.02		Delivery Charge	first 20000	10.6384	0.1380	10.7765
3.03			over 20000	9.9578	0.1292	10.0870
3.04		Gas Supply Load Balancing		0.0033	0.0009	0.0042
3.05		Gas Supply Transportation		5.1042	(0.2825)	4.8217
3.06		Gas Supply Commodity - System		15.2837	0.0611	15.3448
3.07		Gas Supply Commodity - Buy/Sell		15.2613	0.0611	15.3224
	RATE 100					
4.01		Customer Charge		$121.52	$0.49	$122.01
4.02		Demand Charge (Cents/Month/m³)		8.1900	0.0000	8.1900
4.03		Delivery Charge	first 14,000	5.1166	0.0137	5.1303
4.04			next 28,000	3.7576	0.0137	3.7713
4.05			over 42,000	3.1986	0.0137	3.2123
4.06		Gas Supply Load Balancing		0.4808	0.0227	0.5055
4.07		Gas Supply Transportation		5.1042	(0.2825)	4.8217
4.08		Gas Supply Commodity - System		15.3469	0.0120	15.3588
		Gas Supply Commodity - Buy/Sell		15.3283	0.0120	15.3402
	RATE 110					
5.01		Customer Charge		$585.00	$2.37	$587.37
5.02		Demand Charge (Cents/Month/m³)		22.9100	0.0000	22.9100
5.03		Delivery Charge	first 1,000,000	0.5918	0.0083	0.6000
5.04			over 1,000,000	0.4418	0.0083	0.4500
5.05		Load Balancing Commodity		0.1332	0.0068	0.1400
5.06		Gas Supply Transportation		5.1042	(0.2825)	4.8217
5.07		Gas Supply Commodity - System		15.2837	0.0611	15.3448
5.08		Gas Supply Commodity - Buy/Sell		15.2613	0.0611	15.3224

NOTE : * Cents unless otherwise noted.

SUMMARY OF PROPOSED RATE CHANGE BY RATE CLASS (con't)

		Col.1	Col. 2	Col. 3	Col. 4	Col. 5
Item No.	Rate No.		Rate Block m³	EB-2010-0258 cents *	Rate Change cents *	EB-2010-0146 cents *
	RATE 115					
1.01		Customer Charge		$620.86	$1.76	$622.62
1.02		Demand Charge (Cents/Month/m³)		24.3600	0.0000	24.3600
1.03		Delivery Charge	first 1,000,000	0.3252	0.0035	0.3287
1.04			over 1,000,000	0.2252	0.0035	0.2287
1.05		Load Balancing Commodity		0.0448	0.0024	0.0472
1.06		Gas Supply Transportation		5.1042	(0.2825)	4.8217
1.07		Gas Supply Commodity - System		15.2837	0.0611	15.3448
1.08		Gas Supply Commodity - Buy/Sell		15.2613	0.0611	15.3224
	RATE 125					
2.01		Customer Charge		$ 500.00	$0.00	$ 500.00
2.02		Delivery Charge (Cents/Month/m³ of Contract Dmnd)		9.0378	0.0414	9.0792
	RATE 135	DEC - MAR				
3.00		Customer Charge		$114.82	$0.26	$115.08
3.01		Delivery Charge	first 14,000	6.7580	0.0038	6.7618
3.02			next 28,000	5.5580	0.0038	5.5618
3.03			over 42,000	5.1580	0.0038	5.1618
3.04		Gas Supply Load Balancing		0.0000	0.0000	0.0000
3.05		Gas Supply Transportation		5.1042	(0.2825)	4.8217
3.06		Gas Supply Commodity - System		15.3462	0.0794	15.4256
3.07		Gas Supply Commodity - Buy/Sell		15.3238	0.0794	15.4032
	RATE 135	APR - NOV				
3.08		Customer Charge		$114.82	$0.26	$115.08
3.09		Delivery Charge	first 14,000	2.0580	0.0038	2.0618
3.10			next 28,000	1.3580	0.0038	1.3618
3.11			over 42,000	1.1580	0.0038	1.1618
3.12		Gas Supply Load Balancing		0.0000	0.0000	0.0000
3.13		Gas Supply Transportation		5.1042	(0.2825)	4.8217
3.14		Gas Supply Commodity - System		15.3462	0.0794	15.4256
3.15		Gas Supply Commodity - Buy/Sell		15.3238	0.0794	15.4032
	RATE 145					
4.00		Customer Charge		$122.73	$0.61	$123.34
4.01		Demand Charge (Cents/Month/m³)		8.2300	0.000	8.2300
4.02		Delivery Charge	first 14,000	2.8352	0.0107	2.8458
4.03			next 28,000	1.4762	0.0107	1.4868
4.04			over 42,000	0.9172	0.0107	0.9278
4.05		Gas Supply Load Balancing		0.3611	0.0174	0.3785
4.06		Gas Supply Transportation		5.1042	(0.2825)	4.8217
4.07		Gas Supply Commodity - System		15.4626	0.0474	15.5100
4.08		Gas Supply Commodity - Buy/Sell		15.4402	0.0474	15.4876
	RATE 170					
5.00		Customer Charge		$278.27	$1.04	$279.31
5.01		Demand Charge (Cents/Month/m³)		4.0900	0.0000	4.0900
5.02		Delivery Charge	first 1,000,000	0.5211	0.0032	0.5244
5.03			over 1,000,000	0.3211	0.0032	0.3244
5.04		Gas Supply Load Balancing		0.2024	0.0081	0.2105
5.05		Gas Supply Transportation		5.1042	(0.2825)	4.8217
5.06		Gas Supply Commodity - System		15.2837	0.0611	15.3448
5.07		Gas Supply Commodity - Buy/Sell		15.2613	0.0611	15.3224

NOTE : * Cents unless otherwise noted.

SUMMARY OF PROPOSED RATE CHANGE BY RATE CLASS (con't)

Item No.	Rate No.	Col.1	Col. 2 Rate Block m³	Col. 3 EB-2010-0258 cents *	Col. 4 Rate Change cents *	Col. 5 EB-2010-0146 cents *
	RATE 200					
1.00		Customer Charge		$0.00	$0.00	$0.00
1.01		Demand Charge (Cents/Month/m³)		14.7000	0.0000	14.7000
1.02		Delivery Charge		1.1218	0.0075	1.1293
1.03		Gas Supply Load Balancing		0.5180	0.0223	0.5403
1.04		Gas Supply Transportation		5.1042	(0.2825)	4.8217
1.05		Gas Supply Commodity - System		15.2837	0.0611	15.3448
1.06		Gas Supply Commodity - Buy/Sell		15.2613	0.0611	15.3224
	RATE 300	FIRM SERVICE				
2.00		Monthly Customer Charge		$500.00	$0.00	$500.00
2.01		Demand Charge (Cents/Month/m³)		24.8117	0.1136	24.9253
		INTERRUPTIBLE SERVICE				
2.02		Minimum Delivery Charge (Cents/Month/m³)		0.3566	0.0016	0.3582
2.03		Maximum Delivery Charge (Cents/Month/m³)		0.9789	0.0045	0.9834
	RATE 315					
		Monthly Customer Charge		$150.00	$0.00	$150.00
3.00		Space Demand Chg (Cents/Month/m³)		0.0539	0.0046	0.0585
3.01		Deliverability/Injection Demand Chg (Cents/Month/m³)		14.7300	0.5492	15.2792
3.02		Injection & Withdrawal Chg (Cents/Month/m³)		0.3264	0.0236	0.3500
	RATE 320					
4.00		Backstop	All Gas Sold	20.9115	(0.2101)	20.7014
	RATE 316					
		Monthly Customer Charge		$150.00	$0.00	$150.00
5.00		Space Demand Chg (Cents/Month/m³)		0.0539	0.0045	0.0585
5.01		Deliverability/Injection Demand Chg (Cents/Month/m³)		5.0696	0.2015	5.2711
5.02		Injection & Withdrawal Chg (Cents/Month/m³)		0.1066	0.0009	0.1074

NOTE : * Cents unless otherwise noted.

SUMMARY OF PROPOSED RATE CHANGE BY RATE CLASS (con't)

Item No.	Rate No.	Col.1	Col. 2 Rate Block m³	Col. 3 EB-2010-0258 cents *	Col. 4 Change cents *	Col. 5 EB-2010-0146 cents *
	RATE 325					
		Transmission & Compression				
1.00		Demand Charge - ATV ($/Month/10³ m³)		0.1865	0.0005	0.1870
1.01		Demand Charge - Daily Wdrl. ($/Month/10³ m³)		16.8575	0.0472	16.9047
1.02		Commodity Charge		0.9810	0.0065	0.9875
		Storage				
1.03		Demand Charge - ATV ($/Month/10*3 m³)		0.2212	0.0041	0.2253
1.04		Demand Charge - Daily Wdrl. ($/Month/10³ m³)		20.0617	0.3738	20.4355
1.05		Commodity Charge		0.3370	(0.0001)	0.3369
	RATE 330	Storage Service - Firm				
		Demand Charge ($/Month/10³ m³ of ATV)				
2.00		Minimum		0.4077	0.0046	0.4123
2.01		Maximum		2.0385	0.0230	2.0615
		Demand Charge ($/Month/10³ m³ of Daily Withdrawal)				
2.02		Minimum		36.9192	0.4210	37.3402
2.03		Maximum		184.5960	2.1050	186.7010
		Commodity Charge				
2.04		Minimum		1.3180	0.0064	1.3244
2.05		Maximum		6.5900	$0.0320	6.6220
		Storage Service - Interruptible				
		Demand Charge ($/Month/10³ m³ of ATV)				
2.06		Minimum		0.4077	0.0046	0.4123
2.07		Maximum		2.0385	0.0230	2.0615
		Demand Charge ($/Month/10³ m³ of Daily Withdrawal)				
2.08		Minimum		29.5354	0.3368	29.8722
2.09		Maximum		147.6768	$1.6840	149.3608
		Commodity Charge				
2.10		Minimum		1.3180	0.0064	1.3244
2.11		Maximum		6.5900	0.0320	6.6220
		Storage Service - Off Peak				
		Commodity Charge				
2.12		Minimum		0.6774	0.0067	0.6841
2.13		Maximum		38.2222	0.3927	38.6149
	RATE 331	Tecumseh Transmission Service				
		Firm				
		Demand Charge ($/Month/10³ m³ of				
3.00		Maximum Contracted Daily Delivery)		5.2580	0.0120	5.2700
		Interruptible				
3.01		Commodity Charge ($/10³m³ of gas delivered)		0.2070	0.0010	0.2080

NOTE : * Cents unless otherwise noted.

CALCULATION OF GAS SUPPLY CHARGES BY RATE CLASS

Item		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12
		TOTAL	RATE 1	RATE 6	RATE 9	RATE 100	RATE 110	RATE 115	RATE 135	RATE 145	RATE 170	RATE 200	REFERENCE
	DERIVATION OF GAS SUPPLY CHARGE												
	GAS SUPPLY COSTS ($000)												
1.1	Annual Commodity	896,014	513,726	342,203	63	-	9,873	63	92	3,419	7,642	18,934	
1.2	Bad Debt Commodity	7,663	3,711	3,915	-	-	-	-	0	37	-	-	
1.3	System Gas Fee	1,311	751	501	0	-	14	0	0	5	11	28	
1.4	Return on Rate Base - Working Cash	953	546	364	0	-	10	0	0	4	8	20	
1	Total Commodity Costs	905,940	518,735	346,982	63	-	9,898	63	93	3,465	7,661	18,982	
	VOLUMES (10^3 m^3)												
2.1	System and Buy/Sell Volumes	5,853,968	3,356,349	2,235,728	408	-	64,501	410	600	22,339	49,927	123,704	
2.2	System Volumes	5,853,968	3,356,349	2,235,728	408	-	64,501	410	600	22,339	49,927	123,704	
	GAS SUPPLY CHARGE SYSTEM (¢/m^3)												
3.1	Annual Commodity	15.3061	15.3061	15.3061	15.3061	-	15.3061	15.3061	15.3061	15.3061	15.3061	15.3061	1.1 / 2.1
3.2	Bad Debt Commodity	0.1309	0.1106	0.1751	-	-	-	-	0.0808	0.1653	-	-	1.2 / 2.1
3.3	System Gas Fee	0.0224	0.0224	0.0224	0.0224	-	0.0224	0.0224	0.0224	0.0224	0.0224	0.0224	1.3 / 2.2
3.4	Return on Rate Base - Working Cash	0.0163	0.0163	0.0163	0.0163	-	0.0163	0.0163	0.0163	0.0163	0.0163	0.0163	1.4 / 2.1
3	System Gas Supply Charge	15.4757	15.4553	15.5199	15.3448	-	15.3448	15.3448	15.4256	15.5100	15.3448	15.3448	
	GAS SUPPLY CHARGE BUY/SELL(¢/m3)												
4.1	Annual Commodity	15.3061	15.3061	15.3061	15.3061	-	15.3061	15.3061	15.3061	15.3061	15.3061	15.3061	1.1 / 2.1
4.2	Bad Debt Commodity	0.1309	0.1106	0.1751	-	-	-	-	0.0808	0.1653	-	-	1.2 / 2.1
4.3	Return on Rate Base - Working Cash	0.0163	0.0163	0.0163	0.0163	-	0.0163	0.0163	0.0163	0.0163	0.0163	0.0163	1.4 / 2.1
4	Buy/Sell Gas Supply Charge	15.4533	15.4329	15.4975	15.3224	-	15.3224	15.3224	15.4032	15.4876	15.3224	15.3224	

CALCULATION OF GAS SUPPLY LOAD BALANCING & TRANSPORTATION CHARGES BY RATE CLASS

Item		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12
		TOTAL	RATE 1	RATE 6	RATE 9	RATE 100	RATE 110	RATE 115	RATE 135	RATE 145	RATE 170	RATE 200	REFERENCE
	DERIVATION OF LOAD BALANCING CHARGES												
	ANNUAL LOAD BALANCING COSTS ($000)												
5.1	Peak	11,981	6,546	5,224	-	-	71	24	-	-	-	117	
5.2	Seasonal	23,887	11,794	10,512	0	-	257	95	-	392	517	320	
5.3	Return on Rate Base - Gas in Inventory	30,901	15,257	13,599	0	-	333	123	-	507	669	413	
5	Total Load Balancing	66,769	33,596	29,335	0	-	661	242	-	898	1,186	850	
	VOLUMES (10^3 m^3)												
6.1	Annual Deliveries	11,276,393	4,764,426	4,518,434	558	-	471,855	513,097	50,028	237,331	563,271	157,393	
7	**ANNUAL LOAD BALANCING CHARGE (¢/m3)**		0.7052	0.6492	0.0042	-	0.1400	0.0472	-	0.3785	0.2105	0.5403	5.0 / 6
	DERIVATION OF TRANSPORTATION CHARGES												
8	Pipeline Annual incl. some M12 (upstream	359,154	184,986	145,346	27	-	9,610	1,272	1,390	4,439	6,119	5,965	
	VOLUMES (10^3 m^3)												
9	Total Transportation Volumes	7,448,681	3,836,515	3,014,405	558	-	199,310	26,383	28,838	92,073	126,895	123,704	
10	**PROPOSED TRANSPORTATION CHARGE (¢/m^3)**		4.8217	4.8217	4.8217	4.8217	4.8217	4.8217	4.8217	4.8217	4.8217	4.8217	

CALCULATION OF SEASONAL CREDIT FOR RATE 135, 145, 170 & 200

RATE 135		
Seasonal Credits Applicable to Rate 135	**$**	**(422)**
Annual Volume (103 m3)		50,028
Mean Daily Volume (103 m3)		137
Annual Seasonal Credits	$	(3.08)
Payable from December to March	$	(0.77)
RATE 145		
Seasonal Credits Applicable to Rate 145	**$**	**(1,300)**
Annual Volume (103 m3)		237,331
Mean Daily Volume (103 m3)		
16 Hours		650
72 Hours		-
Annual Seasonal Credits		
16 Hours	$	(2.00)
Payable from December to March	$	(0.50)
72 Hours	$	(0.45)
Payable from December to March	$	(0.11)
Seasonal Credits Applicable to Rate 145		
16 Hours	$	(1,300.45)
72 Hours	$	-
RATE 170		
Seasonal Credits Applicable to Rate 170	**$**	**(6,790)**
Annual Volume (103 m3)		563,271
Mean Daily Volume (103 m3)		1,543
Annual Seasonal Credits	$	(4.40)
Payable from December to March	$	(1.10)
RATE 200		
Seasonal Credits Applicable to Rate 200	**$**	**(105)**
Annual Volume (103 m3)		8,674
Mean Daily Volume (103 m3)		24
Annual Seasonal Credits	$	(4.40)
Payable from December to March	$	(1.10)

DETAILED REVENUE CALCULATION

Item No.		Col. 1 Rate Block m³		Col. 2 EB-2010-0146 Bills & Volumes 10³ m³	Col. 3 EB-2010-0146 Rate cents*	Col. 4 EB-2010-0146 Revenues $000
	RATE 1					
1.1	Customer Charge	Bills		21,650,268	$19.00	411,355
1.2	Delivery Charge	first	30	621,360	7.3060	45,396
1.3		next	55	926,565	6.8353	63,334
1.4		next	85	1,016,069	6.4665	65,704
1.5		over	170	2,200,433	6.1919	136,249
1.	Total Distribution Charge			4,764,426		722,039
2.1	Gas Supply Load Balancing			4,764,426	0.7052	33,596
2.2	Gas Supply Transportation			3,836,515	4.8217	184,986
3.1	Gas Supply Commodity - System			3,356,349	15.4553	518,734
3.2	Gas Supply Commodity - Buy/Sell			0	15.4329	0
3.	Total Gas Supply Charge			3,356,349		518,734
4.1	TOTAL DISTRIBUTION			4,764,426		722,039
4.2	TOTAL GAS SUPPLY LOAD BALANCING			4,764,426		218,582
4.3	TOTAL GAS SUPPLY COMMODITY			3,356,349		518,734
4.	TOTAL RATE 1			**4,764,426**		1,459,355
5.	Adj. Factor	0.9999				
6.	ADJUSTED REVENUE					**1,459,269**

NOTE: * Cents unless otherwise noted.

DETAILED REVENUE CALCULATION

		Col. 1	Col. 2	Col. 3	Col. 4
			EB-2010-0146		
Item No.		Rate Block m³	Bills & Volumes 10³ m³	Rate cents*	Revenues $000
	RATE 6				
1.1	Customer Charge	Bills	1,929,889	$65.00	125,443
1.2	Delivery Charge	First 500	569,624	6.9584	39,637
1.3		Next 1050	685,942	5.3193	36,488
1.4		Next 4500	1,210,064	4.1719	50,482
1.5		Next 7000	692,512	3.4343	23,783
1.6		Next 15250	564,404	3.1066	17,534
1.7		Over 28300	795,888	3.0246	24,072
1.	Total Distribution Charge		4,518,434		317,439
2.1	Gas Supply Load Balancing		4,518,434	0.6492	29,335
2.2	Gas Supply Transportation		3,014,405	4.8217	145,346
3.1	Gas Supply Commodity - System		2,235,728	15.5199	346,983
3.2	Gas Supply Commodity - Buy/Sell		0	15.4975	0
3.	Total Gas Supply Charge		2,235,728		346,983
4.1	TOTAL DISTRIBUTION		4,518,434		317,439
4.2	TOTAL GAS SUPPLY LOAD BALANCING		4,518,434		174,681
4.3	TOTAL GAS SUPPLY COMMODITY		2,235,728		346,983
4.	TOTAL RATE 6		**4,518,434**		839,103
5.	Adj. Factor	1.000			
6.	ADJUSTED REVENUE				**839,053**

NOTE: * Cents unless otherwise noted.

DETAILED REVENUE CALCULATION

Item No.		Col. 1 Rate Block m³	Col. 2 Bills & Volumes 10³ m³	Col. 3 Rate cents*	Col. 4 Revenues $000
			EB-2010-0146		
	RATE 9				
1.1	Customer Charge	Bills	130	$235.89	31
1.2	Delivery Charge	first 20000	512	10.7765	55
1.3		over 20000	47	10.0870	5
1.	Total Distribution Charge		558		91
2.1	Gas Supply Load Balancing		558	0.0042	0
2.2	Gas Supply Transportation		558	4.8217	27
3.1	Gas Supply Commodity - System		408	15.3448	63
3.2	Gas Supply Commodity - Buy/Sell		0	15.3224	0
3.	Total Gas Supply Charge		408		63
4.1	TOTAL DISTRIBUTION		558		91
4.2	TOTAL GAS SUPPLY LOAD BALANCING		558		27
4.3	TOTAL GAS SUPPLY COMMODITY		408		63
4	TOTAL RATE 9		**558**		**180**

		Rate Block m³	Contracts & Volumes 10³ m³	Rate cents*	Revenues $000
			EB-2010-0146		
	RATE 100				
1.1	Customer Charge	Contracts	0	$122.01	0
1.2	Demand Charge		0	8.19	0
1.3	Delivery Charge	first 14,000	0	5.1303	0
1.4		next 28,000	0	3.7713	0
1.5		over 42,000	0	3.2123	0
1	Total Distribution Charge		0		0
2.1	Gas Supply Load Balancing		0	0.5055	0
2.2	Gas Supply Transportation		0	4.8217	0
3.1	Gas Supply Commodity - System		0	15.3588	0
3.2	Gas Supply Commodity - Buy/Sell		0	15.3402	0
3	Total Gas Supply Charge		0		0
4.1	TOTAL DISTRIBUTION		0		0
4.2	TOTAL GAS SUPPLY LOAD BALANCING		0		0
4.3	TOTAL GAS SUPPLY COMMODITY		0		0
4	TOTAL RATE 100		**0**		**0**

NOTE: * Cents unless otherwise noted.

DETAILED REVENUE CALCULATION

		Col. 1	Col. 2	Col. 3	Col. 4
			EB-2010-0146		
Item No.		Rate Block m³	Contracts & Volumes 10^3 m³	Rate cents*	Revenues $000
	RATE 110				
1.1	Customer Charge	Contracts	2,448	$587.37	1,438
1.2	Demand Charge		27,320	22.9100	6,259
1.3	Delivery Charge	first 1,000,000	443,782	0.6000	2,663
1.4		over 1,000,000	28,073	0.4500	126
1.	Total Distribution Charge		471,855		10,486
2.1	Load Balancing Commodity		471,855	0.1400	661
2.2	Gas Supply Transportation		199,310	4.8217	9,610
2.	Total Gas Supply Load Balancing				10,271
3.1	Gas Supply Commodity - System		64,501	15.3448	9,898
3.2	Gas Supply Commodity - Buy/Sell		0	15.3224	0
3.	Total Gas Supply Charge		64,501		9,898
4.1	TOTAL DISTRIBUTION		471,855		10,486
4.2	TOTAL GAS SUPPLY LOAD BALANCING		471,855		10,271
4.3	TOTAL GAS SUPPLY COMMODITY		64,501		9,898
4.	TOTAL RATE 110		**471,855**		**30,656**

			EB-2010-0146		
		Rate Block m³	Contracts & Volumes 10^3 m³	Rate cents*	Revenues $000
	RATE 115				
6.6	Customer Charge	Contracts	408	$622.62	254
6.2	Demand Charge		19,631	24.3600	4,782
6.3	Delivery Charge	first 1,000,000	162,230	0.3287	533
6.4		over 1,000,000	350,867	0.2287	802
6	Total Distribution Charge		513,097		6,372
7.1	Load Balancing Commodity		513,097	0.0472	242
7.2	Gas Supply Transportation		26,383	4.8217	1,272
7	Total Gas Supply Load Balancing				1,514
8.1	Gas Supply Commodity - System		410	15.3448	63
8.2	Gas Supply Commodity - Buy/Sell		0	15.3224	0
8.	Total Gas Supply Charge		410		63
9.1	TOTAL DISTRIBUTION		513,097		6,372
9.2	TOTAL GAS SUPPLY LOAD BALANCING		513,097		1,514
9.3	TOTAL GAS SUPPLY COMMODITY		410		63
9.	TOTAL RATE 115		**513,097**		**7,949**

NOTE: * Cents unless otherwise noted.

DETAILED REVENUE CALCULATION

Item No.		Col. 1 Rate Block m³	Col. 2 EB-2010-0146 Contracts & Volumes 10³ m³	Col. 3 Rate cents*	Col. 4 Revenues $000
	RATE 125				
1.1	Customer Charge		48	$ 500.00	24
1.2	Demand Charge		80,056	9.0792	7,268
1.	Total Distribution Charge		80,056		7,292

Item No.		Col. 1 Rate Block m³	Col. 2 EB-2010-0146 Contracts & Volumes 10³ m³	Col. 3 Rate cents*	Col. 4 Revenues $000
	RATE 135				
	DEC to MAR				
1.1	Customer Charge	Contracts	131	$115.08	15
1.2	Delivery Charge	first 14,000	530	6.7618	36
1.3		next 28,000	814	5.5618	45
1.4		over 42,000	2,458	5.1618	127
1.	Total Distribution Charge		3,802		223
2.1	Gas Supply Load Balancing		3,802	0.0000	0
2.2	Gas Supply Transportation		2,076	4.8217	100
2.3	Seasonal Credit				(422)
3.1	Gas Supply Commodity - System		67	15.4256	10
3.2	Gas Supply Commodity - Buy/Sell		0	15.4032	0
3.	Total Gas Supply Charge		67		10
4.	SUB-TOTAL WINTER				-88
	APR to NOV				
5.1	Customer Charge	Contracts	264	$115.08	30
5.2	Delivery Charge	first 14,000	3,504	2.0618	72
5.3		next 28,000	6,783	1.3618	92
5.4		over 42,000	35,939	1.1618	418
5.	Total Distribution Charge		46,226		613
6.1	Gas Supply Load Balancing		46,226	0.0000	0
6.2	Gas Supply Transportation		26,761	4.8217	1,290
7.1	Gas Supply Commodity - System		533	15.4256	82
7.2	Gas Supply Commodity - Buy/Sell		0	15.4032	0
7.	Total Gas Supply Charge		533		82
8.	SUB-TOTAL SUMMER				1,985
9.1	TOTAL DISTRIBUTION		50,028		836
9.2	TOTAL GAS SUPPLY LOAD BALANCING		50,028		969
9.3	TOTAL GAS SUPPLY COMMODITY		600		93
9.	TOTAL RATE 135		**50,028**		**1,897**

NOTE: * Cents unless otherwise noted.

DETAILED REVENUE CALCULATION

		Col. 1	Col. 2	Col. 3	Col. 4
			EB-2010-0146		
Item No.		Rate Block m³	Contracts & Volumes 10^3 m³	Rate cents*	Revenues $000
	RATE 145				
1.1	Customer Charge	Contracts	2,244	$123.34	277
1.2	Demand Charge		22,841	8.2300	1,880
1.2	Delivery Charge	first 14,000	29,784	2.8458	848
1.3		next 28,000	50,262	1.4868	747
1.4		over 42,000	157,285	0.9278	1,459
1.	Total Distribution Charge		237,331		5,211
2.1	Gas Supply Load Balancing		237,331	0.3785	898
2.2	Gas Supply Transportation		92,073	4.8217	4,439
2.3	Curtailment Credit				(1,300)
3.1	Gas Supply Commodity - System		22,339	15.5100	3,465
3.2	Gas Supply Commodity - Buy/Sell		0	15.4876	0
3.	Total Gas Supply Charge		22,339		3,465
4.1	TOTAL DISTRIBUTION		237,331		5,211
4.2	TOTAL GAS SUPPLY LOAD BALANCING		237,331		4,037
4.3	TOTAL GAS SUPPLY COMMODITY		22,339		3,465
4.	TOTAL RATE 145		**237,331**		**12,713**

			EB-2010-0146		
		Rate Block m³	Contracts & Volumes 10^3 m³	Rate cents*	Revenues $000
	RATE 170				
6.6	Customer Charge	Contracts	468	$279.31	131
6.2	Demand Charge		50,890	4.0900	2,081
6.3	Delivery Charge	first 1,000,000	343,862	0.5244	1,803
6.4		over 1,000,000	219,408	0.3244	712
6	Total Distribution Charge		563,271		4,727
7.1	Gas Supply Load Balancing		563,271	0.2105	1,186
7.7	Gas Supply Transportation		126,895	4.8217	6,119
7.3	Curtailment Credit				(6,790)
8.1	Gas Supply Commodity - System		49,927	15.3448	7,661
8.2	Gas Supply Commodity - Buy/Sell		0	15.3224	0
8.	Total Gas Supply Charge		49,927		7,661
9.1	TOTAL DISTRIBUTION		563,271		4,727
9.2	TOTAL GAS SUPPLY LOAD BALANCING		563,271		514
9.3	TOTAL GAS SUPPLY COMMODITY		49,927		7,661
9.	TOTAL RATE 170		**563,271**		**12,902**

NOTE: * Cents unless otherwise noted.

DETAILED REVENUE CALCULATION

Item No.		Col. 1 Rate Block m³	Col. 2 EB-2010-0146 Contracts & Volumes 10^3 m³	Col. 3 Rate cents*	Col. 4 Revenues $000
	RATE 200				
1.1	Customer Charge	Contracts	12	$0.00	0
1.2	Demand Charge		13,334	14.7000	1,960
1.3	Delivery Charge		157,393	1.1293	1,777
1.	Total Distribution Charge		157,393		3,738
2.1	Gas Supply Load Balancing		157,393	0.5403	850
2.2	Gas Supply Transportation		123,704	4.8217	5,965
2.3	Curtailment Credit				(105)
3.1	Gas Supply Commodity - System		123,704	15.3448	18,982
3.2	Gas Supply Commodity - Buy/Sell		0	15.3224	0
3.	Total Gas Supply Charge		123,704		18,982
4.1	TOTAL DISTRIBUTION		157,393		3,738
4.2	TOTAL GAS SUPPLY LOAD BALANCING		157,393		6,710
4.3	TOTAL GAS SUPPLY COMMODITY		123,704		18,982
4.	TOTAL RATE 200		**157,393**		**29,430**

		Rate Block m³	EB-2010-0146 Contracts & Volumes 10^3 m³	Rate cents*	Revenues $000
	RATE 300				
	Firm				
	Customer Charge		108	$500.00	54
	Demand Charge		1,005	24.9253	251
	Interruptible				
	Minimum Delivery Charge		30,000	0.3582	107
	Maximum Delivery Charge		0	0.9834	0
8.	TOTAL RATE 300		**0**		**412**

NOTE: * Cents unless otherwise noted.

ANNUAL BILL COMPARISON - RESIDENTIAL CUSTOMERS

(A) EB-2010-0146 @ 37.69 MJ/m³ vs (B) EB-2010-0258 @ 37.69 MJ/m³

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Heating & Water Htg.				Heating, Water Htg. & Other Uses			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
1.1	VOLUME	m³	3,064	3,064	0	0.0%	4,691	4,691	0	0.0%
1.2	CUSTOMER CHG.	$	228.00	216.00	12.00	5.6%	228.00	216.00	12.00	5.6%
1.3	DISTRIBUTION CHG.	$	199.62	211.29	(11.67)	-5.5%	300.95	318.49	(17.54)	-5.5%
1.4	LOAD BALANCING	§ $	169.35	176.77	(7.42)	-4.2%	259.28	270.64	(11.36)	-4.2%
1.5	SALES COMMDTY	$	473.55	472.54	1.01	0.2%	725.01	723.47	1.54	0.2%
1.6	TOTAL SALES	$	1,070.52	1,076.60	(6.08)	-0.6%	1,513.24	1,528.60	(15.36)	-1.0%
1.7	TOTAL T-SERVICE	$	596.97	604.06	(7.09)	-1.2%	788.23	805.13	(16.90)	-2.1%
1.8	SALES UNIT RATE	$/m³	0.3494	0.3514	(0.0020)	-0.6%	0.3226	0.3259	(0.0033)	-1.0%
1.9	T-SERVICE UNIT RATE	$/m³	0.1948	0.1971	(0.0023)	-1.2%	0.1680	0.1716	(0.0036)	-2.1%
1.10	SALES UNIT RATE	$/GJ	9.270	9.323	(0.0526)	-0.6%	8.559	8.646	(0.0869)	-1.0%
1.11	T-SERVICE UNIT RATE	$/GJ	5.169	5.231	(0.0614)	-1.2%	4.458	4.554	(0.0956)	-2.1%

			Heating Only				Heating & Water Htg.			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
2.1	VOLUME	m³	1,955	1,955	0	0.0%	2,005	2,005	0	0.0%
2.2	CUSTOMER CHG.	$	228.00	216.00	12.00	5.6%	228.00	216.00	12.00	5.6%
2.3	DISTRIBUTION CHG.	$	128.04	135.52	(7.48)	-5.5%	133.24	141.05	(7.81)	-5.5%
2.4	LOAD BALANCING	§ $	108.06	112.80	(4.74)	-4.2%	110.82	115.69	(4.87)	-4.2%
2.5	SALES COMMDTY	$	302.14	301.49	0.65	0.2%	309.87	309.23	0.64	0.2%
2.6	TOTAL SALES	$	766.24	765.81	0.43	0.1%	781.93	781.97	(0.04)	0.0%
2.7	TOTAL T-SERVICE	$	464.10	464.32	(0.22)	0.0%	472.06	472.74	(0.68)	-0.1%
2.8	SALES UNIT RATE	$/m³	0.3919	0.3917	0.0002	0.1%	0.3900	0.3900	(0.0000)	0.0%
2.9	T-SERVICE UNIT RATE	$/m³	0.2374	0.2375	(0.0001)	0.0%	0.2354	0.2358	(0.0003)	-0.1%
2.10	SALES UNIT RATE	$/GJ	10.399	10.393	0.0058	0.1%	10.347	10.348	(0.0005)	0.0%
2.11	T-SERVICE UNIT RATE	$/GJ	6.299	6.302	(0.0030)	0.0%	6.247	6.256	(0.0090)	-0.1%

§ The Load Balancing Charge shown here includes proposed transportation charges

ANNUAL BILL COMPARISON - RESIDENTIAL CUSTOMERS

(A) EB-2010-0146 @ 37.69 MJ/m³ vs (B) EB-2010-0258 @ 37.69 MJ/m³

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Heating, Pool Htg. & Other Uses				**General & Water Htg.**			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
3.1	VOLUME	m^3	5,048	5,048	0	0.0%	1,081	1,081	0	0.0%
3.2	CUSTOMER CHG.	$	228.00	216.00	12.00	5.6%	228.00	216.00	12.00	5.6%
3.3	DISTRIBUTION CHG.	$	323.66	342.54	(18.88)	-5.5%	75.22	79.63	(4.41)	-5.5%
3.4	LOAD BALANCING	§ $	278.99	291.27	(12.28)	-4.2%	59.76	62.38	(2.62)	-4.2%
3.5	SALES COMMDTY	$	780.18	778.54	1.64	0.2%	167.07	166.72	0.35	0.2%
3.6	TOTAL SALES	$	1,610.83	1,628.35	(17.52)	-1.1%	530.05	524.73	5.32	1.0%
3.7	TOTAL T-SERVICE	$	830.65	849.81	(19.16)	-2.3%	362.98	358.01	4.97	1.4%
3.8	SALES UNIT RATE	$/m³	0.3191	0.3226	(0.0035)	-1.1%	0.4903	0.4854	0.0049	1.0%
3.9	T-SERVICE UNIT RATE	$/m³	0.1646	0.1683	(0.0038)	-2.3%	0.3358	0.3312	0.0046	1.4%
3.10	SALES UNIT RATE	$/GJ	8.467	8.559	(0.0921)	-1.1%	13.010	12.879	0.1306	1.0%
3.11	T-SERVICE UNIT RATE	$/GJ	4.366	4.467	(0.1007)	-2.3%	8.909	8.787	0.1220	1.4%

§ The Load Balancing Charge shown here includes proposed transportation charges

ANNUAL BILL COMPARISON - COMMERCIAL & INDUSTRIAL CUSTOMERS

(A) EB-2010-0146 @ 37.69 MJ/m³ vs (B) EB-2010-0258 @ 37.69 MJ/m³

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Commercial Heating & Other Uses				**Com. Htg., Air Cond'ng & Other Uses**			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
1.1	VOLUME	m³	22,606	22,606	0	0.0%	29,278	29,278	0	0.0%
1.2	CUSTOMER CHG.	$	780.00	720.00	60.00	8.3%	780.00	720.00	60.00	8.3%
1.3	DISTRIBUTION CHG.	$	1,190.41	1,232.01	(41.60)	-3.4%	1,527.35	1,580.74	(53.39)	-3.4%
1.4	LOAD BALANCING	§ $	1,236.77	1,295.49	(58.72)	-4.5%	1,601.78	1,677.86	(76.08)	-4.5%
1.5	SALES COMMDTY	$	3,508.43	3,505.72	2.71	0.1%	4,543.90	4,540.40	3.50	0.1%
1.6	TOTAL SALES	$	6,715.61	6,753.22	(37.61)	-0.6%	8,453.03	8,519.00	(65.97)	-0.8%
1.7	TOTAL T-SERVICE	$	3,207.18	3,247.50	(40.32)	-1.2%	3,909.13	3,978.60	(69.47)	-1.7%
1.8	SALES UNIT RATE	$/m³	0.2971	0.2987	(0.0017)	-0.6%	0.2887	0.2910	(0.0023)	-0.8%
1.9	T-SERVICE UNIT RATE	$/m³	0.1419	0.1437	(0.0018)	-1.2%	0.1335	0.1359	(0.0024)	-1.7%
1.10	SALES UNIT RATE	$/GJ	7.882	7.926	(0.0441)	-0.6%	7.660	7.720	(0.0598)	-0.8%
1.11	T-SERVICE UNIT RATE	$/GJ	3.764	3.812	(0.0473)	-1.2%	3.543	3.605	(0.0630)	-1.7%

			Medium Commercial Customer				**Large Commercial Customer**			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
2.1	VOLUME	m³	169,563	169,563	0	0.0%	339,125	339,125	0	0.0%
2.2	CUSTOMER CHG.	$	780.00	720.00	60.00	8.3%	780.00	720.00	60.00	8.3%
2.3	DISTRIBUTION CHG.	$	6,410.59	6,634.63	(224.04)	-3.4%	11,737.56	12,147.68	(410.12)	-3.4%
2.4	LOAD BALANCING	§ $	9,276.70	9,717.24	(440.54)	-4.5%	18,553.33	19,434.44	(881.11)	-4.5%
2.5	SALES COMMDTY	$	26,316.00	26,295.65	20.35	0.1%	52,631.83	52,591.17	40.66	0.1%
2.6	TOTAL SALES	$	42,783.29	43,367.52	(584.23)	-1.3%	83,702.72	84,893.29	(1,190.57)	-1.4%
2.7	TOTAL T-SERVICE	$	16,467.29	17,071.87	(604.58)	-3.5%	31,070.89	32,302.12	(1,231.23)	-3.8%
2.8	SALES UNIT RATE	$/m³	0.2523	0.2558	(0.0034)	-1.3%	0.2468	0.2503	(0.0035)	-1.4%
2.9	T-SERVICE UNIT RATE	$/m³	0.0971	0.1007	(0.0036)	-3.5%	0.0916	0.0953	(0.0036)	-3.8%
2.10	SALES UNIT RATE	$/GJ	6.694	6.786	(0.0914)	-1.3%	6.549	6.642	(0.0931)	-1.4%
2.11	T-SERVICE UNIT RATE	$/GJ	2.577	2.671	(0.0946)	-3.5%	2.431	2.527	(0.0963)	-3.8%

§ The Load Balancing Charge shown here includes proposed transportation charges

ANNUAL BILL COMPARISON - COMMERCIAL & INDUSTRIAL CUSTOMERS

(A) EB-2010-0146 @ 37.69 MJ/m³ vs (B) EB-2010-0258 @ 37.69 MJ/m³

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Industrial General Use				**Industrial Heating & Other Uses**			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
3.1	VOLUME	m³	43,285	43,285	0	0.0%	63,903	63,903	0	0.0%
3.2	CUSTOMER CHG.	$	780.00	720.00	60.00	8.3%	780.00	720.00	60.00	8.3%
3.3	DISTRIBUTION CHG.	$	2,110.41	2,184.20	(73.79)	-3.4%	2,830.51	2,929.43	(98.92)	-3.4%
3.4	LOAD BALANCING	§ $	2,368.10	2,480.56	(112.46)	-4.5%	3,496.10	3,662.12	(166.02)	-4.5%
3.5	SALES COMMDTY	$	6,717.79	6,712.61	5.18	0.1%	9,917.66	9,910.01	7.65	0.1%
3.6	TOTAL SALES	$	11,976.30	12,097.37	(121.07)	-1.0%	17,024.27	17,221.56	(197.29)	-1.1%
3.7	TOTAL T-SERVICE	$	5,258.51	5,384.76	(126.25)	-2.3%	7,106.61	7,311.55	(204.94)	-2.8%
3.8	SALES UNIT RATE	$/m³	0.2767	0.2795	(0.0028)	-1.0%	0.2664	0.2695	(0.0031)	-1.1%
3.9	T-SERVICE UNIT RATE	$/m³	0.1215	0.1244	(0.0029)	-2.3%	0.1112	0.1144	(0.0032)	-2.8%
3.10	SALES UNIT RATE	$/GJ	7.341	7.415	(0.0742)	-1.0%	7.068	7.150	(0.0819)	-1.1%
3.11	T-SERVICE UNIT RATE	$/GJ	3.223	3.301	(0.0774)	-2.3%	2.951	3.036	(0.0851)	-2.8%

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Medium Industrial Customer				**Large Industrial Customer**			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
4.1	VOLUME	m³	169,563	169,563	0	0.0%	339,124	339,124	0	0.0%
4.2	CUSTOMER CHG.	$	780.00	720.00	60.00	8.3%	780.00	720.00	60.00	8.3%
4.3	DISTRIBUTION CHG.	$	6,564.78	6,794.21	(229.43)	-3.4%	11,852.17	12,266.26	(414.09)	-3.4%
4.4	LOAD BALANCING	§ $	9,276.70	9,717.23	(440.53)	-4.5%	18,553.30	19,434.35	(881.05)	-4.5%
4.5	SALES COMMDTY	$	26,315.99	26,295.67	20.32	0.1%	52,631.68	52,591.01	40.67	0.1%
4.6	TOTAL SALES	$	42,937.47	43,527.11	(589.64)	-1.4%	83,817.15	85,011.62	(1,194.47)	-1.4%
4.7	TOTAL T-SERVICE	$	16,621.48	17,231.44	(609.96)	-3.5%	31,185.47	32,420.61	(1,235.14)	-3.8%
4.8	SALES UNIT RATE	$/m³	0.2532	0.2567	(0.0035)	-1.4%	0.2472	0.2507	(0.0035)	-1.4%
4.9	T-SERVICE UNIT RATE	$/m³	0.0980	0.1016	(0.0036)	-3.5%	0.0920	0.0956	(0.0036)	-3.8%
4.10	SALES UNIT RATE	$/GJ	6.719	6.811	(0.0923)	-1.4%	6.558	6.651	(0.0935)	-1.4%
4.11	T-SERVICE UNIT RATE	$/GJ	2.601	2.696	(0.0954)	-3.5%	2.440	2.537	(0.0966)	-3.8%

§ The Load Balancing Charge shown here includes proposed transportation charges

ANNUAL BILL COMPARISON - LARGE VOLUME CUSTOMERS

(A) EB-2010-0146 @ 37.69 MJ/m³ vs (B) EB-2010-0258 @ 37.69 MJ/m³

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Rate 100 - Small Commercial Firm				Rate 100 - Average Commercial Firm			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
1.1	VOLUME	m³	339,188	339,188	0	0.0%	598,568	598,568	0	0.0%
1.2	CUSTOMER CHG.	$	1,464.12	1,458.24	5.88	0.4%	1,464.12	1,458.24	5.88	0.4%
1.3	DISTRIBUTION CHG.	$	17,653.55	17,607.19	46.36	0.3%	28,095.92	28,014.10	81.82	0.3%
1.4	LOAD BALANCING	$	18,069.27	18,943.75	(874.48)	-4.6%	31,886.99	33,430.20	(1,543.21)	-4.6%
1.5	SALES COMMDTY	$	52,095.13	52,054.84	40.29	0.1%	91,932.73	91,861.64	71.09	0.1%
1.6	TOTAL SALES	$	89,282.07	90,064.02	(781.95)	-0.9%	153,379.76	154,764.18	(1,384.42)	-0.9%
1.7	TOTAL T-SERVICE	$	37,186.94	38,009.18	(822.24)	-2.2%	61,447.03	62,902.54	(1,455.51)	-2.3%
1.8	SALES UNIT RATE	$/m³	0.2632	0.2655	(0.0023)	-0.9%	0.2562	0.2586	(0.0023)	-0.9%
1.9	T-SERVICE UNIT RATE	$/m³	0.1096	0.1121	(0.0024)	-2.2%	0.1027	0.1051	(0.0024)	-2.3%
1.10	SALES UNIT RATE	$/GJ	6.984	7.045	(0.0612)	-0.9%	6.799	6.860	(0.0614)	-0.9%
1.11	T-SERVICE UNIT RATE	$/GJ	2.909	2.973	(0.0643)	-2.2%	2.724	2.788	(0.0645)	-2.3%

			Rate 100 - Small Industrial Firm				Rate 100 - Average Industrial Firm			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
2.1	VOLUME	m³	339,188	339,188	0	0.0%	598,567	598,567	0	0.0%
2.2	CUSTOMER CHG.	$	1,464.12	1,458.24	5.88	0.4%	1,464.12	1,458.24	5.88	0.4%
2.3	DISTRIBUTION CHG.	$	17,926.33	17,880.01	46.32	0.3%	28,337.34	28,255.52	81.82	0.3%
2.4	LOAD BALANCING	$	18,069.27	18,943.74	(874.47)	-4.6%	31,886.93	33,430.13	(1,543.20)	-4.6%
2.5	SALES COMMDTY	$	52,095.14	52,054.83	40.31	0.1%	91,932.56	91,861.48	71.08	0.1%
2.6	TOTAL SALES	$	89,554.86	90,336.82	(781.96)	-0.9%	153,620.95	155,005.37	(1,384.42)	-0.9%
2.7	TOTAL T-SERVICE	$	37,459.72	38,281.99	(822.27)	-2.1%	61,688.39	63,143.89	(1,455.50)	-2.3%
2.8	SALES UNIT RATE	$/m³	0.2640	0.2663	(0.0023)	-0.9%	0.2566	0.2590	(0.0023)	-0.9%
2.9	T-SERVICE UNIT RATE	$/m³	0.1104	0.1129	(0.0024)	-2.1%	0.1031	0.1055	(0.0024)	-2.3%
2.10	SALES UNIT RATE	$/GJ	7.005	7.066	(0.0612)	-0.9%	6.809	6.871	(0.0614)	-0.9%
2.11	T-SERVICE UNIT RATE	$/GJ	2.930	2.995	(0.0643)	-2.1%	2.734	2.799	(0.0645)	-2.3%

ANNUAL BILL COMPARISON - LARGE VOLUME CUSTOMERS

(A) EB-2010-0146 @ 37.69 MJ/m³ vs (B) EB-2010-0258 @ 37.69 MJ/m³

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Rate 145 - Small Commercial Interr.				Rate 145 - Average Commercial Interr.			
			(A)	(B)	CHANGE		(A)	(B)	CHANGE	
					(A) - (B)	%			(A) - (B)	%
3.1	VOLUME	m³	339,188	339,188	0	0.0%	598,568	598,568	0	0.0%
3.2	CUSTOMER CHG.	$	1,480.08	1,472.76	7.32	0.5%	1,480.08	1,472.76	7.32	0.5%
3.3	DISTRIBUTION CHG.	$	9,919.23	9,882.98	36.25	0.4%	14,443.37	14,379.38	63.99	0.4%
3.4	LOAD BALANCING	$	15,778.06	16,677.87	(899.81)	-5.4%	27,844.06	29,432.02	(1,587.96)	-5.4%
3.5	SALES COMMDTY	$	52,608.06	52,447.29	160.77	0.3%	92,837.91	92,554.17	283.74	0.3%
3.6	TOTAL SALES	$	79,785.43	80,480.90	(695.47)	-0.9%	136,605.42	137,838.33	(1,232.91)	-0.9%
3.7	TOTAL T-SERVICE	$	27,177.37	28,033.61	(856.24)	-3.1%	43,767.51	45,284.16	(1,516.65)	-3.3%
3.8	SALES UNIT RATE	$/m³	0.2352	0.2373	(0.0021)	-0.9%	0.2282	0.2303	(0.0021)	-0.9%
3.9	T-SERVICE UNIT RATE	$/m³	0.0801	0.0826	(0.0025)	-3.1%	0.0731	0.0757	(0.0025)	-3.3%
3.10	SALES UNIT RATE	$/GJ	6.241	6.295	(0.0544)	-0.9%	6.055	6.110	(0.0547)	-0.9%
3.11	T-SERVICE UNIT RATE	$/GJ	2.126	2.193	(0.0670)	-3.1%	1.940	2.007	(0.0672)	-3.3%
			Rate 145 - Small Industrial Interr.				Rate 145 - Average Industrial Interr.			
			(A)	(B)	CHANGE		(A)	(B)	CHANGE	
					(A) - (B)	%			(A) - (B)	%
4.1	VOLUME	m³	339,188	339,188	0	0.0%	598,567	598,567	0	0.0%
4.2	CUSTOMER CHG.	$	1,480.08	1,472.76	7.32	0.5%	1,480.08	1,472.76	7.32	0.5%
4.3	DISTRIBUTION CHG.	$	10,192.05	10,155.78	36.27	0.4%	14,684.86	14,620.84	64.02	0.4%
4.4	LOAD BALANCING	$	15,778.07	16,677.87	(899.80)	-5.4%	27,844.02	29,431.92	(1,587.90)	-5.4%
4.5	SALES COMMDTY	$	52,608.06	52,447.30	160.76	0.3%	92,837.75	92,554.03	283.72	0.3%
4.6	TOTAL SALES	$	80,058.26	80,753.71	(695.45)	-0.9%	136,846.71	138,079.55	(1,232.84)	-0.9%
4.7	TOTAL T-SERVICE	$	27,450.20	28,306.41	(856.21)	-3.0%	44,008.96	45,525.52	(1,516.56)	-3.3%
4.8	SALES UNIT RATE	$/m³	0.2360	0.2381	(0.0021)	-0.9%	0.2286	0.2307	(0.0021)	-0.9%
4.9	T-SERVICE UNIT RATE	$/m³	0.0809	0.0835	(0.0025)	-3.0%	0.0735	0.0761	(0.0025)	-3.3%
4.10	SALES UNIT RATE	$/GJ	6.262	6.317	(0.0544)	-0.9%	6.066	6.121	(0.0546)	-0.9%
4.11	T-SERVICE UNIT RATE	$/GJ	2.147	2.214	(0.0670)	-3.0%	1.951	2.018	(0.0672)	-3.3%

ANNUAL BILL COMPARISON - LARGE VOLUME CUSTOMERS

(A) EB-2010-0146 @ 37.69 MJ/m³ vs (B) EB-2010-0258 @ 37.69 MJ/m³

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Rate 110 - Small Ind. Firm - 50% LF				**Rate 110 - Average Ind. Firm - 50% LF**			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
5.1	VOLUME	m³	598,568	598,568	0	0.0%	9,976,121	9,976,121	0	0.0%
5.2	CUSTOMER CHG.	$	7,048.44	7,020.00	28.44	0.4%	7,048.44	7,020.00	28.44	0.4%
5.3	DISTRIBUTION CHG.	$	12,642.09	12,592.60	49.49	0.4%	206,925.87	206,101.24	824.63	0.4%
5.4	LOAD BALANCING	$	29,699.49	31,349.60	(1,650.11)	-5.3%	494,991.06	522,492.59	(27,501.53)	-5.3%
5.5	SALES COMMDTY	$	91,849.06	91,483.33	365.73	0.4%	1,530,815.81	1,524,720.40	6,095.41	0.4%
5.6	TOTAL SALES	$	141,239.08	142,445.53	(1,206.45)	-0.8%	2,239,781.18	2,260,334.23	(20,553.05)	-0.9%
5.7	TOTAL T-SERVICE	$	49,390.02	50,962.20	(1,572.18)	-3.1%	708,965.37	735,613.83	(26,648.46)	-3.6%
5.8	SALES UNIT RATE	$/m³	0.2360	0.2380	(0.0020)	-0.8%	0.2245	0.2266	(0.0021)	-0.9%
5.9	T-SERVICE UNIT RATE	$/m³	0.0825	0.0851	(0.0026)	-3.1%	0.0711	0.0737	(0.0027)	-3.6%
###	SALES UNIT RATE	$/GJ	6.261	6.314	(0.0535)	-0.8%	5.957	6.012	(0.0547)	-0.9%
###	T-SERVICE UNIT RATE	$/GJ	2.189	2.259	(0.0697)	-3.1%	1.886	1.956	(0.0709)	-3.6%

			Rate 110 - Average Ind. Firm - 75% LF				**Rate 115 - Large Ind. Firm - 80% LF**			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
6.1	VOLUME	m³	9,976,120	9,976,120	0	0.0%	69,832,850	69,832,850	0	0.0%
6.2	CUSTOMER CHG.	$	7,048.44	7,020.00	28.44	0.4%	7,471.44	7,450.32	21.12	0.3%
6.3	DISTRIBUTION CHG.	$	159,967.95	159,143.32	824.63	0.5%	870,154.09	867,678.55	2,475.54	0.3%
6.4	LOAD BALANCING	$	494,991.01	522,492.52	(27,501.51)	-5.3%	3,400,109.00	3,595,697.03	(195,588.03)	-5.4%
6.5	SALES COMMDTY	$	1,530,815.67	1,524,720.26	6,095.41	0.4%	10,715,711.18	10,673,043.29	42,667.89	0.4%
6.6	TOTAL SALES	$	2,192,823.07	2,213,376.10	(20,553.03)	-0.9%	14,993,445.71	15,143,869.19	(150,423.48)	-1.0%
6.7	TOTAL T-SERVICE	$	662,007.40	688,655.84	(26,648.44)	-3.9%	4,277,734.53	4,470,825.90	(193,091.37)	-4.3%
6.8	SALES UNIT RATE	$/m³	0.2198	0.2219	(0.0021)	-0.9%	0.2147	0.2169	(0.0022)	-1.0%
6.9	T-SERVICE UNIT RATE	$/m³	0.0664	0.0690	(0.0027)	-3.9%	0.0613	0.0640	(0.0028)	-4.3%
###	SALES UNIT RATE	$/GJ	5.832	5.887	(0.0547)	-0.9%	5.697	5.754	(0.0572)	-1.0%
###	T-SERVICE UNIT RATE	$/GJ	1.761	1.832	(0.0709)	-3.9%	1.625	1.699	(0.0734)	-4.3%

ANNUAL BILL COMPARISON - LARGE VOLUME CUSTOMERS

(A) EB-2010-0146 @ 37.69 MJ/m³ vs (B) EB-2010-0258 @ 37.69 MJ/m³

Item No.			Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8
			Rate 135 - Seasonal Firm				Rate 170 - Average Ind. Interr. - 50% LF			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
7.1	VOLUME	m³	598,567	598,567	0	0.0%	9,976,121	9,976,121	0	0.0%
7.2	CUSTOMER CHG.	$	1,380.96	1,377.84	3.12	0.2%	3,351.72	3,339.24	12.48	0.4%
7.3	DISTRIBUTION CHG.	$	8,378.7	8,355.73	22.93	0.3%	77,367.5	77,045.14	322.33	0.4%
7.4	LOAD BALANCING	$	23,815.72	25,506.75	(1,691.03)	-6.6%	381,761.00	409,135.98	(27,374.98)	-6.7%
7.5	SALES COMMDTY	$	92,332.55	91,857.29	475.26	0.5%	1,530,815.81	1,524,720.40	6,095.41	0.4%
7.6	TOTAL SALES	$	125,907.89	127,097.61	(1,189.72)	-0.9%	1,993,296.00	2,014,240.76	(20,944.76)	-1.0%
7.7	TOTAL T-SERVICE	$	33,575.34	35,240.32	(1,664.98)	-4.7%	462,480.19	489,520.36	(27,040.17)	-5.5%
7.8	SALES UNIT RATE	$/m³	0.2103	0.2123	(0.0020)	-0.9%	0.1998	0.2019	(0.0021)	-1.0%
7.9	T-SERVICE UNIT RATE	$/m³	0.0561	0.0589	(0.0028)	-4.7%	0.0464	0.0491	(0.0027)	-5.5%
7.10	SALES UNIT RATE	$/GJ	5.581	5.634	(0.0527)	-0.9%	5.301	5.357	(0.0557)	-1.0%
7.11	T-SERVICE UNIT RATE	$/GJ	1.488	1.562	(0.0738)	-4.7%	1.230	1.302	(0.0719)	-5.5%

			Rate 170 - Average Ind. Interr. - 75% LF				Rate 170 - Large Ind. Interr. - 75% LF			
			(A)	(B)	CHANGE (A) - (B)	%	(A)	(B)	CHANGE (A) - (B)	%
8.1	VOLUME	m³	9,976,120	9,976,120	0	0.0%	69,832,850	69,832,850	0	0.0%
8.2	CUSTOMER CHG.	$	3,351.72	3,339.24	12.48	0.4%	3,351.72	3,339.24	12.48	0.4%
8.3	DISTRIBUTION CHG.	$	70,182.6	69,860.30	322.34	0.5%	375,710.1	373,453.87	2,256.27	0.6%
8.4	LOAD BALANCING	$	381,760.94	409,135.93	(27,374.99)	-6.7%	2,672,327.02	2,863,951.93	(191,624.91)	-6.7%
8.5	SALES COMMDTY	$	1,530,815.67	1,524,720.26	6,095.41	0.4%	10,715,711.18	10,673,043.29	42,667.89	0.4%
8.6	TOTAL SALES	$	1,986,110.97	2,007,055.73	(20,944.76)	-1.0%	13,767,100.06	13,913,788.33	(146,688.27)	-1.1%
8.7	TOTAL T-SERVICE	$	455,295.30	482,335.47	(27,040.17)	-5.6%	3,051,388.88	3,240,745.04	(189,356.16)	-5.8%
8.8	SALES UNIT RATE	$/m³	0.1991	0.2012	(0.0021)	-1.0%	0.1971	0.1992	(0.0021)	-1.1%
8.9	T-SERVICE UNIT RATE	$/m³	0.0456	0.0483	(0.0027)	-5.6%	0.0437	0.0464	(0.0027)	-5.8%
8.10	SALES UNIT RATE	$/GJ	5.282	5.338	(0.0557)	-1.0%	5.231	5.286	(0.0557)	-1.1%
8.11	T-SERVICE UNIT RATE	$/GJ	1.211	1.283	(0.0719)	-5.6%	1.159	1.231	(0.0719)	-5.8%

Measure of 2011 Revenues vs 2011 Revenue Requirement

December 31, 2011

(millions of dollars)

ITEM NO.	DESCRIPTION	Col. 1 TOTAL	Col. 2 RATE 1	Col. 3 RATE 6	Col. 4 RATE 9	Col. 5 RATE 100	Col. 6 RATE 110	Col. 7 RATE 115	Col. 8 RATE 125	Col. 9 RATE 135	Col.10 RATE 145	Col. 11 RATE 170	Col. 12 RATE 200	Col. 13 RATE 300	Col. 14 RATE 325 & 330	Col. 15 DIRECT PURCHASE
1.	Sales and Delivery Revenue	2,406.02	1,459.27	839.05	0.18	0.00	30.65	7.95	7.29	1.90	12.71	12.90	29.43	0.41	1.60	2.66
2.	Unbilled Revenues	(1.12)	(0.60)	(0.57)	0.00	0.00	(0.02)	0.00	0.00	(0.01)	0.08	(0.00)	0.00	0.00	0.00	0.00
3.	Total Revenues	2,404.89	1,458.67	838.48	0.18	0.00	30.64	7.95	7.29	1.89	12.79	12.90	29.43	0.41	1.60	2.66
4.	Proposed 2011 Revenue Requirement	2,404.89	1,454.73	838.39	0.25	0.00	31.36	7.96	7.34	1.82	14.38	14.32	29.41	0.46	1.60	2.87
5.	Measure of Revenues vs Revenue Requirement	1.00	1.00	1.00	0.71	0.00	0.98	1.00	0.99	1.04	0.89	0.90	1.00	0.89	1.00	0.93

Measure of 2011 Revenues vs 2011 Revenue Requirement
Excluding Gas Supply Commodity
December 31, 2011
(millions of dollars)

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col.10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15
ITEM NO.	DESCRIPTION	TOTAL	RATE 1	RATE 6	RATE 9	RATE 100	RATE 110	RATE 115	RATE 125	RATE 135	RATE 145	RATE 170	RATE 200	RATE 300	RATE 325 & 330	DIRECT PURCHASE
1.	Sales and Delivery Revenue	1,500.08	940.54	492.07	0.12	0.00	20.76	7.89	7.29	1.80	9.25	5.24	10.45	0.41	1.60	2.66
2.	Unbilled Revenues	(1.12)	(0.60)	(0.57)	0.00	0.00	(0.02)	0.00	0.00	(0.01)	0.08	(0.00)	0.00	0.00	0.00	0.00
3.	Total Revenues	1,498.95	939.93	491.50	0.12	0.00	20.74	7.89	7.29	1.80	9.32	5.24	10.45	0.41	1.60	2.66
4.	Proposed 2011 Revenue Requirement	1,498.89	935.96	491.39	0.19	0.00	21.46	7.89	7.34	1.73	10.91	6.66	10.42	0.46	1.60	2.87
5.	Measure of Revenues vs Revenue Requirement excluding Gas Supply Commodity	1.00	1.00	1.00	0.61	0.00	0.97	1.00	0.99	1.04	0.85	0.79	1.00	0.89	1.00	0.93

Total 2011 Revenue Requirement

December 31, 2011

(millions of dollars)

Col. 1 ITEM NO.	Col. 2 DESCRIPTION	Col. 3 TOTAL	Col. 4 RATE 1	Col. 5 RATE 6	Col. 6 RATE 9	Col. 7 RATE 100	Col. 8 RATE 110	Col. 9 RATE 115	Col. 10 RATE 125	Col. 11 RATE 135	Col. 12 RATE 145	Col. 13 RATE 170	Col. 14 RATE 200	Col. 15 RATE 300 Firm	Col. 16 RATE 300 Int	Col. 17 DIRECT PURCHASE	Reference
1	PRODUCT COSTS	906.0	518.8	347.0	0.1	-	9.9	0.1	-	0.1	3.5	7.7	19.0	-	-	-	Ex.B/T3/S10/P4/L1 & Ex.B/T3/S10/P5/L1
2	PIPELINE TRANS. AND LOAD BALANCING	417.7	218.9	174.7	0.0	-	10.2	1.4	-	1.4	4.0	0.4	6.7	-	-	-	Ex.B/T3/S10/P4/L2 & Ex.B/T3/S10/P5/L2
3	STORAGE	152.6	79.7	67.0	0.0	-	1.3	0.5	-	(0.4)	1.2	1.6	1.8	-	-	-	Ex.B/T3/S10/P4/L3 & Ex.B/T3/S10/P5/L3
4	DISTRIBUTION	469.8	276.7	161.9	0.0	-	8.2	5.5	6.9	0.1	4.7	4.0	1.3	0.3	0.1	-	Ex.B/T3/S10/P4/L4 & Ex.B/T3/S10/P5/L4
5	CUSTOMER RELATED	457.2	360.7	87.8	0.2	0.0	1.8	0.6	0.4	0.7	1.0	0.7	0.6	0.1	0.0	2.9	Ex.B/T3/S10/P5/L5
Total 2011 Revenue Requirement		2,403.3	1,454.7	838.4	0.3	0.0	31.4	8.0	7.3	1.8	14.4	14.3	29.4	0.3	0.1	2.9	

2011 Gas Cost to Operations Revenue Requirement

December 31, 2011

(millions of dollars)

Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15	Col. 16	Col. 17	Col. 18
ITEM NO.	DESCRIPTION	TOTAL	RATE 1	RATE 6	RATE 9	RATE 100	RATE 110	RATE 115	RATE 125	RATE 135	RATE 145	RATE 170	RATE 200	RATE 300 Firm	RATE 300 Int	DIRECT PURCHASE	Allocation
	SUPPLY COSTS																
	PRODUCT COSTS																
1.1	Annual Commodity	896.0	513.7	342.2	0.1	-	9.9	0.1	-	0.1	3.4	7.6	18.9	-	-	-	1.1
1	Total Gas Cost	896.0	513.7	342.2	0.1	-	9.9	0.1	-	0.1	3.4	7.6	18.9	-	-	-	-
	PIPELINE TRANS. AND LOAD BALANCING																
2.1	Peak	12.0	6.5	5.2	-	-	0.1	0.0	-	-	-	-	0.1	-	-	-	3.1
2.2	Seasonal	22.8	11.3	10.0	0.0	-	0.2	0.1	-	-	0.4	0.5	0.3	-	-	-	3.2
2.3	Annual - Transportation	362.9	186.9	146.9	0.0	-	9.7	1.3	-	1.4	4.5	6.2	6.0	-	-	-	1.4
2.4	Seasonal Credit	(8.2)	-	-	-	-	-	-	-	-	(1.3)	(6.8)	(0.1)	-	-	-	-
2	Total Pipeline Trans. Cost	389.5	204.7	162.1	0.0	-	10.0	1.4	-	1.4	3.6	(0.1)	6.3	-	-	-	-
	STORAGE																
3.1	Deliverability	60.1	32.9	26.2	-	-	0.4	0.1	-	-	-	-	0.6	-	-	-	3.1
3.2	Space	57.5	28.4	25.3	0.0	-	0.6	0.2	-	-	0.9	1.2	0.8	-	-	-	3.2
3.3	Seasonal Credit	(0.4)	-	-	-	-	-	-	-	(0.4)	-	-	-	-	-	-	-
3	Total Storage	117.2	61.3	51.5	0.0	-	1.0	0.4	-	(0.4)	0.9	1.2	1.4	-	-	-	-
	DISTRIBUTION																
4.1	Commodity	13.3	5.6	5.3	0.0	-	0.6	0.6	-	0.1	0.3	0.7	0.2	-	-	-	1.3
4	Total Distribution	13.3	5.6	5.3	0.0	-	0.6	0.6	-	0.1	0.3	0.7	0.2	-	-	-	-
	Total 2011 Gas Cost to Operations Revenue Requirement	1,416.0	785.3	561.2	0.1	-	21.4	2.4	-	1.1	8.2	9.4	26.8	-	-	-	-

2011 Distribution Revenue Requirement

December 31, 2011

(millions of dollars)

Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15	Col. 16	Col. 17
ITEM NO.	DESCRIPTION	TOTAL	RATE 1	RATE 6	RATE 9	RATE 100	RATE 110	RATE 115	RATE 125	RATE 135	RATE 145	RATE 170	RATE 200	RATE 300 Firm	RATE 300 Int	DIRECT PURCHASE
	SUPPLY RELATED															
1	PRODUCT RELATED	10.0	5.1	4.8	0.0	-	0.0	0.0	-	0.0	0.0	0.0	0.0	-	-	-
2	LOAD BALANCING RELATED	28.2	14.2	12.6	(0.0)	-	0.2	(0.0)	-	(0.0)	0.4	0.5	0.4	-	-	-
	FACILITIES' COSTS															
3	STORAGE	35.3	18.5	15.5	0.0	-	0.3	0.1	-	-	0.3	0.3	0.4	-	-	-
4	DISTRIBUTION	456.4	271.0	156.5	0.0	-	7.7	4.9	6.9	0.0	4.5	3.3	1.2	0.3	0.1	-
5	CUSTOMER RELATED	457.2	360.7	87.8	0.2	0.0	1.8	0.6	0.4	0.7	1.0	0.7	0.6	0.1	0.0	2.9
Total 2011 Distribution Revenue Requirement		987.2	669.4	277.2	0.2	0.0	9.9	5.5	7.3	0.7	6.2	4.9	2.6	0.3	0.1	2.9

2011 Y- Factor Revenue Requirement
December 31, 2011
(millions of dollars)

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15	Col. 16
ITEM NO.	DESCRIPTION	TOTAL	RATE 1	RATE 6	RATE 9	RATE 100	RATE 110	RATE 115	RATE 125	RATE 135	RATE 145	RATE 170	RATE 200	RATE 300 Firm	RATE 300 Int	DIRECT PURCHASE	Assignment
	Y Factor: Other																
1.1	2011 Gas in Storage and Working Cash Carrying Cost	30.9	15.3	13.6	0.0	0.0	0.3	0.1	0.0	0.0	0.5	0.7	0.4	0.0	0.0		3.2
1.2	DSM 2011	26.7	10.3	9.9	0.0	0.0	1.7	1.5	0.0	0.0	1.6	1.8	0.0	0.0	0.0		Direct
1.3	CIS/ Customer Care 2011	97.4	89.4	8.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0		4.1
		155.0	114.9	31.5	0.0	0.0	2.0	1.6	0.0	0.0	2.1	2.4	0.4	0.0	0.0		
	Y Factor: Capital Investment																
1.4	2011 Leave to Construct	3.5	1.7	1.4	0.0	0.0	0.1	0.1	0.2	0.0	0.0	0.0	0.0	0.0	0.0		2.1
		3.5	1.7	1.4	0.0	0.0	0.1	0.1	0.2	0.0	0.0	0.0	0.0	0.0	0.0		
1.5	**Total Y-Factor: Other & Capital Investment**	158.5	116.6	32.9	0.0	0.0	2.1	1.6	0.2	0.0	2.2	2.5	0.5	0.0	0.0		

2011 Distribution Revenue Requirement with Y- Factor Detail

December 31, 2011

(millions of dollars)

		Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15
ITEM NO.	DESCRIPTION	TOTAL	RATE 1	RATE 6	RATE 9	RATE 100	RATE 110	RATE 115	RATE 125	RATE 135	RATE 145	RATE 170	RATE 200	RATE 300 Firm	RATE 300 Int	DIRECT PURCHASE
1.0	DRR before Y- Factors	828.7	552.8	244.3	0.2	0.0	7.9	3.9	7.1	0.7	4.0	2.4	2.1	0.3	0.1	2.9
	Y Factor: Other															
1.1	2011 Gas in Storage and Working Cash Carrying Cost	30.9	15.3	13.6	0.0	0.0	0.3	0.1	0.0	0.0	0.5	0.7	0.4	0.0	0.0	0.0
1.2	DSM 2011	26.7	10.3	9.9	0.0	0.0	1.7	1.5	0.0	0.0	1.6	1.8	0.0	0.0	0.0	0.0
1.3	CIS/ Customer Care 2011	97.4	89.4	8.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Y Factor: Capital Investment															
1.4	2011 Leave to Construct	3.5	1.7	1.4	0.0	0.0	0.1	0.1	0.2	0.0	0.0	0.0	0.0	0.0	0.0	0.0
1.5	Total Y-Factor	158.5	116.6	32.9	0.0	0.0	2.1	1.6	0.2	0.0	2.2	2.5	0.5	0.0	0.0	0.0
1.6	DRR with Y-Factors	987.2	669.4	277.2	0.2	0.0	9.9	5.5	7.3	0.7	6.2	4.9	2.6	0.3	0.1	2.9

Allocators
December 31, 2011

	Col. 1	Col. 2	Col. 3	Col. 4	Col. 5	Col. 6	Col. 7	Col. 8	Col. 9	Col. 10	Col. 11	Col. 12	Col. 13	Col. 14	Col. 15
	FACTOR TOTAL	RATE 1	RATE 6	RATE 9	RATE 100	RATE 110	RATE 115	RATE 125	RATE 135	RATE 145	RATE 170	RATE 200	RATE 300 Firm	RATE 300 Int	Direct Purchase
COMMODITY RESPONSIBILITY															
1.1 Annual Sales	5,854.0	3,356.3	2,235.7	0.4	0.0	64.5	0.4	0.0	0.6	22.3	49.9	123.7	0.0	0.0	0.0
1.2 Bundled Annual Deliveries	11,276.4	4,764.4	4,518.4	0.6	0.0	471.9	513.1	0.0	50.0	237.3	563.3	157.4	0.0	0.0	0.0
1.3 Total Annual Deliveries	11,306.4	4,764.4	4,518.4	0.6	0.0	471.9	513.1	0.0	50.0	237.3	563.3	157.4	0.0	30.0	0.0
1.4 Bundled Transportation Deliveries	7,448.7	3,836.5	3,014.4	0.6	0.0	199.3	26.4	0.0	28.8	92.1	126.9	123.7	0.0	0.0	0.0
DISTRIBUTION CAPACITY RESPONSIBILITY															
2.1 Delivery Demand TP	104,967.1	49,494.0	42,630.5	3.5	0.0	1,779.5	1,592.5	7,148.9	5.1	729.6	303.2	1,190.7	89.8	0.0	0.0
2.2 Delivery Demand HP	96,715.5	49,494.0	42,630.5	3.5	0.0	1,779.5	1,592.5	0.0	5.1	729.6	303.2	0.0	89.8	88.1	0.0
2.3 Delivery Demand LP	95,626.8	49,494.0	42,630.5	3.5	0.0	1,779.5	503.7	0.0	5.1	729.6	303.2	0.0	89.8	88.1	0.0
2.4 Cust. Rel Plant	1,965,538.0	1,804,189.0	160,827.0	11.0	0.0	204.0	34.0	4.0	33.0	187.0	39.0	1.0	8.0	1.0	0.0
STORAGE RESPONSIBILITY															
3.1 Deliverability	51.9	28.3	22.6	0.0	0.0	0.3	0.1	0.0	0.0	0.0	0.0	0.5	0.0	0.0	0.0
3.2 Space	2,623.0	1,295.1	1,154.4	0.0	0.0	28.2	10.4	0.0	0.0	43.0	56.8	35.1	0.0	0.0	0.0
CUSTOMER RESPONSIBILITY															
4.1 Total Customer Count	1,965,538.0	1,804,189.0	160,827.0	11.0	0.0	204.0	34.0	4.0	33.0	187.0	39.0	1.0	8.0	1.0	0.0
4.2 Services	1,900,200.0	1,687,622.7	209,500.1	13.7	0.0	1,012.2	284.4	2.4	206.6	908.5	590.7	0.0	43.4	15.1	0.0

Allocation Percentages
December 31, 2011

	Col. 1 FACTOR TOTAL	Col. 2 RATE 1	Col. 3 RATE 6	Col. 4 RATE 9	Col. 5 RATE 100	Col. 6 RATE 110	Col. 7 RATE 115	Col. 8 RATE 125	Col. 9 RATE 135	Col. 10 RATE 145	Col. 11 RATE 170	Col. 12 RATE 200	Col. 13 RATE 300 Firm	Col. 14 RATE 300 Int	Col. 15 Direct Purchase
COMMODITY RESPONSIBILITY															
1.1 Annual Sales	1.0000	0.5733	0.3819	0.0001	0.0000	0.0110	0.0001	0.0000	0.0001	0.0038	0.0085	0.0211	0.0000	0.0000	0.0000
1.2 Bundled Annual Deliveries	1.0000	0.4225	0.4007	0.0000	0.0000	0.0418	0.0455	0.0000	0.0044	0.0210	0.0500	0.0140	0.0000	0.0000	0.0000
1.3 Total Annual Deliveries	1.0000	0.4214	0.3996	0.0000	0.0000	0.0417	0.0454	0.0000	0.0044	0.0210	0.0498	0.0139	0.0000	0.0027	0.0000
1.4 Bundled Transportation Deliveries	1.0000	0.5151	0.4047	0.0001	0.0000	0.0268	0.0035	0.0000	0.0039	0.0124	0.0170	0.0166	0.0000	0.0000	0.0000
DISTRIBUTION CAPACITY RESPONSIBILITY															
2.1 Delivery Demand TP	1.0000	0.4715	0.4061	0.0000	0.0000	0.0170	0.0152	0.0681	0.0000	0.0070	0.0029	0.0113	0.0009	0.0000	0.0000
2.2 Delivery Demand HP	1.0000	0.5117	0.4408	0.0000	0.0000	0.0184	0.0165	0.0000	0.0001	0.0075	0.0031	0.0000	0.0009	0.0009	0.0000
2.3 Delivery Demand LP	1.0000	0.5176	0.4458	0.0000	0.0000	0.0186	0.0053	0.0000	0.0001	0.0076	0.0032	0.0000	0.0009	0.0009	0.0000
2.4 Cust. Rel Plant	1.0000	0.9179	0.0818	0.0000	0.0000	0.0001	0.0000	0.0000	0.0000	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000
STORAGE RESPONSIBILITY															
3.1 Deliverability	1.0000	0.5463	0.4360	0.0000	0.0000	0.0059	0.0020	0.0000	0.0000	0.0000	0.0000	0.0098	0.0000	0.0000	0.0000
3.2 Space	1.0000	0.4937	0.4401	0.0000	0.0000	0.0108	0.0040	0.0000	0.0000	0.0164	0.0216	0.0134	0.0000	0.0000	0.0000
CUSTOMER RESPONSIBILITY															
4.1 Total Customer Count	1.0000	0.9179	0.0818	0.0000	0.0000	0.0001	0.0000	0.0000	0.0000	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000
4.2 Services	1.0000	0.8881	0.1103	0.0000	0.0000	0.0005	0.0001	0.0000	0.0001	0.0005	0.0003	0.0000	0.0000	0.0000	0.0000

APPENDIX “C”

(Not Used)

APPENDIX “D”

2011 Deferral and Variance Accounts

ACCOUNTING TREATMENT FOR A
PURCHASED GAS VARIANCE ACCOUNT
("2011 PGVA")

For the 2011 Fiscal Year
(January 1, 2011 to December 31, 2011)

The purpose of the 2011 PGVA is to record the effect of price variances between actual 2011 gas purchase prices and the forecast prices that underpin the revenue rates to be charged in 2011. Without this deferral account, the ratepayers and the Company are exposed to the risk of purchased gas price variances, which could unduly penalize or benefit one party at the benefit or expense of the other. Lower than forecast gas purchase prices would result in an over recovery from the customers and higher prices would result in an under recovery to the Company. This deferral account ensures that such effects are eliminated.

Methodology

The actual unit cost is determined by dividing the total commodity and transportation costs (less the demand charges related to unutilized TransCanada firm service transportation capacity, if any) plus any other costs associated with emerging gas pricing mechanisms incurred in the month by the actual volumes purchased in the month. The rate differential between the PGVA reference price and the actual unit cost of the purchases, multiplied by the actual volumes purchased, is recorded in the PGVA monthly.

The fixed cost component of the TransCanada firm service transportation costs (i.e., Transportation Demand Charge) is included in the determination of the reference price. However, any demand charges relating to unutilized transportation capacity, either forecast or actual, are excluded. This treatment of forecast and actual Transportation Demand Charges for unutilized transportation capacity is consistent with the Board's concerns that these amounts be excluded from the PGVA.

Since all transportation costs on volumes purchased by the Company related to forecast utilized capacity are included in the determination of the PGVA reference price, any changes in the TransCanada tolls will be recorded in the PGVA. Any toll changes related to the cost of forecast unutilized capacity will not be recorded in the PGVA and therefore, requires separate adjustment. The inclusion of changes in TransCanada tolls in the PGVA is consistent with past practice.

Since the transportation tolls for the Alliance and Vector pipelines that were used in the determination of the PGVA reference price were based upon an estimate, any variation between the actual transportation costs (including associated fuel costs) and the estimated transportation costs will be recorded in the PGVA.

Since transportation costs related to the transport of Western Canada Bundled T-service volumes are not included in the derivation of the PGVA reference price, changes in TransCanada tolls will be recorded in the PGVA as a separate adjustment.

For the period January 1, 2011 to December 31, 2011 expenditures related to TransCanada's Storage Transportation Services, including balancing fees related to TransCanada's Limited Balancing Agreement, will be recorded in the 2011 PGVA. The 2011 PGVA will also record amounts related to a Limited Balancing Agreement with Union Gas.

The PGVA will record adjustments related to transactional services activities which are designed to record the impact of direct and avoided costs between the PGVA and the TSDA. These adjustments are required to ensure appropriate allocation of costs and benefits to the underlying transactions and appropriate recording of amounts in the 2011 PGVA and 2011 TSDA for purposes of deferral account dispositions.

In addition, the 2011 PGVA will record the amounts related to unforecast penalty revenues received from interruptible customers who do not comply with the Company's curtailment requirements, unauthorized overrun gas revenues, the use of electronic bulletin boards, and the unforecast Unabsorbed Demand Charge ("UDC") that arises as a consequence of the Company voluntarily leaving transportation capacity unutilized in order to gain a net benefit for the customer by purchasing lower priced unforecast discretionary delivered supplies.

The 2011 PGVA will also record an inventory valuation adjustment every time a recalculated “Utility Price” or PGVA Reference Price comes into effect at the beginning of a quarter. The adjustment consists of the storage inventory valuation adjustment necessary to price actual opening inventory volumes at a rate equal to the Board approved quarterly PGVA reference price.

The 2011 PGVA will also record any refund/collection associated with Board approved Gas Cost Adjustment Riders.

The Company will record, at the time a Banked Gas Account Balance is purchased from a customer, the difference in the amount payable to the customer and the amount included in the PGVA (Transportation Service Rider A). This amount would be credited to a sub-account of the PGVA. In the event the Company incurs unforecast UDC costs as a result of having to purchase Banked Gas Account Balances then the amount in such sub-account will be used to offset corresponding UDC costs. All amounts remaining in this sub-account, after offsetting these UDC costs, will be rolled up into the PGVA.

The commodity sale price on the disposition of Banked Gas Account Balances, the incentive sale price, is set at 120% of an average Empress price over the 12 months of the contractual year. Any amount in excess of 100% of the gas supply charge stated in the applicable rate schedule, net of the commodity related bad debt, will be included in the PGVA.

Simple interest is to be calculated on the opening monthly balance of the 2011 PGVA using the Board Approved EB-2006-0117 interest rate methodology. The balance of the 2011 PGVA, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

Accounting Entries

1. To record the monthly gas purchase variance:

Debit:	2011 PGVA	(Account 179.701)
Credit:	Gas in Storage	(Account 152.000)
	or	
Debit:	Gas in Storage	(Account 152.000)
Credit:	2011 PGVA	(Account 179.701)

To record the total rate variance on the current month's gas purchases.

2. TransCanada Toll changes related to forecast un-utilized transportation capacity:

Debit:	2011 PGVA	(Account 179.701)
Credit:	Accounts Payable	(Account 259.000)
	or	
Debit:	Sundry Accounts Receivable	(Account 141.030)
Credit:	2011 PGVA	(Account 179.701)

To record the amounts related to TransCanada toll changes on forecast unutilized transportation capacity.

3. TransCanada Toll changes related to Western Canada Bundled T-Service transportation capacity:

Debit:	2011 PGVA	(Account 179. 701)
Credit:	Accounts Payable	(Account 259. 000)
	or	
Debit:	Sundry Accounts Receivable	(Account 141. 030)
Credit:	2011 PGVA	(Account 179. 701)

To record the amounts related to TransCanada toll changes on Western Canada Bundled T-Service transportation capacity.

4. Transactional services activities:

Debit/Credit:	2011 TSDA	(Account 179. 801)
Debit/Credit:	Various accounts	(Account ___. ___)
Credit/Debit:	2011 PGVA	(Account 179. 701)

To record adjustments for direct and avoided costs related to Transactional Services activities between the 2011 PGVA and 2011 TSDA, and other accounts such as Gas Costs, Gas Stored Underground and Storage Demand Charges.

5. Electronic bulletin boards:

Debit:	2011 PGVA	(Account 179. 701)
Credit:	Accounts Payable	(Account 259. 000)

To record the amounts related to the Company's use of electronic bulletin boards.

6. Unforecast penalty revenues:

Debit:	Accounts Receivable	(Account 140. 010)
Credit:	2011 PGVA	(Account 179. 701)

To record unforecast penalty revenues received from interruptible customers who do not comply with the Company's curtailment requirements.

7. Voluntary UDC:

Debit:	2011 PGVA	(Account 179. 701)
Credit:	Accounts Payable	(Account 259. 000)

To record voluntary UDC as a result of purchasing lower priced unforecast discretionary delivered supplies.

8. Inventory valuation adjustment:

Credit/Debit:	Gas In Storage	(Account 152. 000)
Debit/Credit:	2011 PGVA	(Account 179. 701)

To record the adjustment necessary to value actual inventory volumes at a rate equal to the 2011 PGVA reference price.

9. Refund or collection of the Gas Cost Adjustment Rider:

Debit/Credit:	2011 PGVA	(Account 179. 701)
Credit/Debit:	Accounts Receivable	(Account 140. 010)

To record the amounts refunded or collected from customers through the Gas Cost Adjustment Rider.

10. Purchase of banked gas account balance:

Debit:	Gas In Storage	(Account 152. 000)
Credit:	2011 PGVA	(Account 179. 701)

To record the purchase of the Banked Gas Account Balance less the Transportation Service Rider A.

11. Unforecast UDC:

Debit:	2011 PGVA	(Account 179. 701)
Credit:	Accounts Payable	(Account 259. 000)

To record unforecast UDC costs resulting from the purchase of Banked Gas Account Balances from T-Service customers.

12. Sales in excess of 100% of the applicable gas supply charge:

Debit:	Other Income	(Account 319. 010)
Credit:	2011 PGVA	(Account 179. 701)

To record the amount of sales in excess of 100% of the gas supply charge stated in the applicable rate schedule, net of the commodity related bad debt amount.

13. Interest accrual:

Debit:	2011 PGVA - Interest Receivable	(Account 179. 711)
Credit:	Interest Expense	(Account 323.000)
	or	
Debit:	Interest Expense	(Account 323.000)
Credit:	2011 PGVA - Interest Payable	(Account 179. 711)

To record simple interest on the opening monthly balance of the 2011 PGVA using the Board Approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR A
TRANSACTIONAL SERVICES DEFERRAL ACCOUNT
("2011 TSDA")

For the 2011 Fiscal Year
(January 1, 2011 to December 31, 2011)

The purpose of the 2011 TSDA is to record the ratepayer share of the net revenue, from transportation and storage related transactional services, in excess of the $8.0 million ratepayer guarantee and the operation and maintenance costs associated with storage related transactional services.

As determined in the NGEIR Decision with Reasons (EB-2005-0551), there is a distinction, and differing sharing mechanisms, associated with transportation related and storage related transactional services. Net transportation related transactional services revenue will employ a 75:25 sharing mechanism between the Company's ratepayers and shareholders, but net storage related transactional services revenue will employ a 90:10 sharing mechanism between ratepayers and shareholders.

Net revenue is defined as gross revenues for providing these services less any direct incremental costs incurred, plus, any avoided costs. Direct incremental costs represent those direct costs incurred as a result of a transactional service activity and avoided costs are those costs that have been avoided as a result of a transactional service activity. Typical direct incremental costs and avoided costs would include transportation costs, fuel costs, charges for name changes, re-direct charges, etc.

In EB-2005-0001, the Board determined that the operating and maintenance expenses (O&M) such as salaries, benefits, promotion, legal fees, etc. are properly recovered from ratepayers through rates outside of the TS sharing mechanism. This methodology remains in effect for O&M related to transportation related transactional services, but no longer applies to O&M related to storage related transactional services. The NGEIR Decision with Reasons (EB-2005-0551) determined that incremental O&M related to providing storage related transactional services will now be applied against the corresponding net revenues.

Simple interest is to be calculated on the opening monthly balance of the 2011 TSDA using the Board Approved EB-2006-0117 interest rate methodology. The balance of the 2011 TSDA, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

Accounting Entries

1. To record Transactional Services revenues and costs:

Debit/Credit:	Other Income	(Account 319. 010)
Credit/Debit:	2011 TSDA	(Account 179. 801)

To record the ratepayer portion of net revenues generated from transactional services activities in excess of the guaranteed amount, inclusive of O&M costs related to TS storage activities.

2. Allocation of costs and benefits to Transactional Services activities:

Debit/Credit:	2011 TSDA	(Account 179. 801)
Debit/Credit:	Various accounts	(Account ___. ___)
Credit/Debit:	2011 PGVA	(Account 179. 701)

To record adjustments for direct and avoided costs related to transactional services activities between the 2011 PGVA and 2011 TSDA, and other accounts such as Gas Costs, Gas Stored Underground and Storage Demand Charges.

3. Interest accrual:

Debit:	Interest Expense	(Account 323. 000)
Credit:	2011 TSDA - Interest Payable	(Account 179. 811)

To record simple interest on the opening monthly balance of the 2011 TSDA using the Board Approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR AN
UNACCOUNTED FOR GAS VARIANCE ACCOUNT
("2011 UAFVA")

For the 2011 Fiscal Year
(January 1, 2011 to December 31, 2011)

The purpose of the 2011 UAFVA is to record the cost of gas that is associated with volumetric variances between the actual volume of unaccounted for gas ("UAF") and the 2011 Board approved UAF volumetric forecast.

The gas costs associated with the UAF variance account will be calculated at the end of calendar 2011 based on the estimated volumetric variance between the 2011 Board approved level and the estimate of the 2011 actual UAF. An adjustment will be made to the UAFVA in the subsequent year to record any differences between the estimated UAF and actual UAF.

The UAF annual variance will be allocated on a monthly basis in proportion to actual sales and costed at the monthly PGVA reference price.

Carrying costs for the UAFVA will be calculated on the allocated monthly balances using the Board Approved EB-2006-0117 interest rate methodology. The balance of the UAFVA, together with the carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

Accounting Entries

1. To record the estimated volumetric variance between the December 31, 2011 actual UAF and the Board Approved level:

Debit/Credit:	2011 UAFVA	(Account 179. 851)
Credit/Debit:	Gas Costs	(Account 623. 010)

To record the costs associated with the volumetric variance related to unaccounted for gas.

2. Interest accrual:

Debit/Credit:	Interest on 2011 UAFVA	(Account 179. 861)
Credit/Debit:	Interest expense	(Account 323. 000)

To record simple interest on the opening monthly balance of the 2011 UAFVA using the Board Approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR A
STORAGE AND TRANSPORTATION DEFERRAL ACCOUNT
("2011 S&TDA")

For the 2011 Fiscal Year
(January 1, 2011 to December 31, 2011)

The purpose of the 2011 S&TDA is to record the difference between the forecast of Storage and Transportation rates (both cost of service and market based pricing) included in the Company's approved rates and the final Storage and Transportation rates (both cost of service and market based pricing) incurred by the company. It will also be used to record variances between the forecast Storage and Transportation rebate programs and the final rebates received by the company. The accounting treatment for the S&TDA is in line with that established for the 2008 S&TDA, which recognized that storage and transportation services may be provided to the Company by suppliers other than Union Gas and at market based rates.

The 2011 S&TDA will also record the variance between the forecast Storage and Transportation demand levels and the actual Storage and Transportation demand levels. In addition, this account will be used to record amounts related to deferral account dispositions received or invoiced from Storage and Transportation suppliers.

The 2011 S&TDA will also record the variance between the forecasted commodity cost for fuel and the updated QRAM Reference Price.

Simple interest is to be calculated on the opening monthly balance of the 2011 S&TDA using the Board Approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

Accounting Entries

1. Storage and Transportation rate variance:

[(Final Storage and Transportation rates) – (Storage and Transportation rates underpinning the Company's 2011 rates)] **X** Actual storage and/or transportation volumes

Debit/Credit:	2011 S&TDA	(Account 179. 881)
Credit/Debit:	Gas in Storage	(Account 152. 000)
	or	
Credit/Debit:	Gas Costs	(Account 623. 010)

To record the difference between the Storage and Transportation rates included in the Company's 2011 rates and the final Storage and Transportation rates.

2. To record variances in the Storage and Transportation rebate programs:

Debit:	Sundry Accounts Receivable	(Account 141. 030)
Credit:	2011 S&TDA	(Account 179. 881)
	or	
Debit:	2011 S&TDA	(Account 179. 881)
Credit:	Accounts Payable	(Account 259. 000)

To record the difference between the Storage and Transportation rebate programs included in the Company's 2011 rates and the final rebates received by the Company.

3. To record Storage and Transportation deferral account disposition:

Debit:	Sundry Accounts Receivable	(Account 141. 030)
Credit:	2011 S&TDA	(Account 179. 881)
	or	
Debit:	2011 S&TDA	(Account 179. 881)
Credit:	Accounts Payable	(Account 259. 000)

To record amounts related to deferral account dispositions received or invoiced from Storage and Transportation.

4. Inventory valuation adjustment:

Debit/Credit:	2011 S&TDA	(Account 179. 881)
Credit/Debit:	Gas In Storage	(Account 152. 000)

To record adjustments to storage and transmission fuel costs associated with quarterly price changes.

5. Interest accrual:

Debit/Credit:	Interest on 2011 S&TDA	(Account 179. 891)
Credit/Debit:	Interest Income/Expense	(Account 323. 000)

To record simple interest on the opening monthly balance of the 2011 S&TDA using the Board Approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR A
CARBON DIOXIDE OFFSET CREDITS DEFERRAL ACCOUNT
("2011 CDOCDA")

For the 2011 Fiscal Year
(January 1, 2011 to December 31, 2011)

The purpose of the 2011 CDOCDA is to record amounts which represent proceeds resulting from the sale of or other dealings in earned carbon dioxide offset credits. This deferral account was originally approved by the Board in its Natural Gas Generic DSM proceeding, docket EB-2006-0021.

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

Accounting Entries

1. To record the proceeds resulting from the sale of earned carbon dioxide offset credits:

Debit:	Various accounts	(Account ___. ___)
Credit:	2011 CDOCDA	(Account 179. 501)

Proceeds arising from carbon dioxide offset credits earned.

2. Interest accrual:

Debit:	Interest expense	(Account 323. 000)
Credit:	Interest on 2011 CDOCDA	(Account 179. 511)

To record simple interest on the opening monthly balance of the 2011 CDOCDA using the Board approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR A
CLASS ACTION SUIT DEFERRAL ACCOUNT
(“2011 CASDA”)

For the 2011 Fiscal Year
(January 1, 2011 to December 31, 2011)

The Board, in it’s EB-2007-0731 Decision, approved the use of an ongoing or continuance of a CASDA account, which the 2011 CASDA will be, as an extension of the Board Approved 2007 CASDA in order to record amounts as allowed within the account and bring forward any un-cleared account balance for future disposition. In that decision, the Board approved the recovery of amounts in the CASDA along with interest, over the five year period of 2008 through 2012. The 2007 CASDA, which included amounts brought forward from 2006, recorded the Company’s legal costs, plaintiff costs, costs of actuarial advice, costs of historical records analysis incurred in defending the 5% late payment penalty lawsuit against the Company, and the eventual settlement amount.

Simple interest is to be calculated on the opening monthly balance of the 2011 CASDA using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner to be designated by the Board in a future rate hearing.

Accounting Entries

1. To record the costs associated with defending the Company's late payment penalty:

Debit:	2011 CASDA	(Account 179. 401)
Credit:	Accounts payable	(Account 251. 010)
Credit:	2010 CASDA	(Account 179. 400)

To record the third party incremental costs incurred to defend the late payment penalty class action lawsuit and to roll forward un-cleared amounts from the board approved 2010 CASDA.

2. Interest accrual:

Debit:	Interest on 2011 CASDA	(Account 179. 411)
Credit:	Interest expense	(Account 323. 000)
Credit:	Interest on 2010 CASDA	(Account 179. 410)

To record simple interest on the opening monthly balance of the 2011 CASDA using the Board approved EB-2006-0117 interest rate methodology and to roll forward un-cleared amounts from the board approved 2010 interest on CASDA account.

ACCOUNTING TREATMENT FOR A
DEFERRED REBATE ACCOUNT
("2011 DRA")

For the 2011 Fiscal Year
(January 1, 2011 to December 31, 2011)

The purpose of the 2011 DRA is to record any amounts payable to, or receivable from, customers of Enbridge Gas Distribution as a result of the clearing of deferral and variance accounts authorized by the Board which remain outstanding due to the Company's inability to locate such customers. The account will also include amounts arising from differences between actual and forecast volumes used for the purpose of clearing deferral account balances.

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

Accounting Entries

1. Disposition of non-gas supply deferral accounts:

Debit:	2010 EPESDA	(Account 179. 600)
Debit:	2010 ESMDA	(Account 179. 580)
Debit:	2010 EFTPBSDA	(Account 179. 080)
Credit:	2011 CASDA	(Account 179. 401)
Credit:	2010 GDARCDA	(Account 179. 200)
Credit:	2010 MPFDA	(Account 179. 540)
Credit:	2010 URICDA	(Account 179. 630)
Credit:	2010 IFRSTCDA	(Account 179. 460)
Credit:	2010 OBSDA	(Account 179. 420)
Credit:	2010 OBAVA	(Account 179. 520)
Credit:	2010 MDVMDA	(Account 179. 560)
Credit:	2009 SSMVA	(Account 179. 129)
Debit/Credit:	2010 DRA	(Account 179. 000)
Debit/Credit:	2010 OHCVA	(Account 179. 220)
Debit/Credit:	2010 URCMVA	(Account 179. 670)
Debit/Credit:	2010 AUTUVA	(Account 179. 650)
Debit/Credit:	2010 TRRCVA	(Account 179. 440)
Debit/Credit:	2010 OBRVA	(Account 179. 480)
Debit/Credit:	2009 DSMVA	(Account 179. 029)
Debit/Credit:	2009 LRAM	(Account 179. 109)
Debit/Credit:	Interest on DA's & VA's – various	(Account 179. ___)
Credit/Debit:	2011 DRA	(Account 179. 001)

2. Disposition of gas supply deferral accounts:

Debit:	2010 TSDA	(Account 179. 800)
Debit/Credit:	2010 S&TDA	(Account 179. 880)
Debit/Credit:	2010 UAFVA	(Account 179. 850)
Debit/Credit:	Interest on DA’s & VA’s –various	(Account 179. ___)
Credit/Debit:	2011 DRA	(Account 179. 001)

3. Refund or collection:

Debit/Credit:	2011 DRA	(Account 179. 001)
Credit/Debit:	Accounts Receivable	(Account 140. 010)

To record the actual amounts refunded to / recovered from customers.

4. Interest accrual:

Debit/Credit:	Interest expense	(Account 323. 000)
Credit/Debit:	Interest on the 2011 DRA	(Account 179. 011)

To record simple interest on the opening monthly balance of the 2011 DRA using the Board approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR AN
ELECTRIC PROGRAM EARNINGS SHARING DEFERRAL ACCOUNT
("2011 EPESDA")

For the 2011 Fiscal Year
(January 1, 2011 to December 31, 2011)

The purpose of the 2011 EPESDA is to track and account for the ratepayer share of net revenues generated by providing DSM services under contract to electric LDCs. The ratepayer share is 50% of net revenues, using fully allocated costs, as was determined in the generic DSM proceeding EB-2006-0021.

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner to be designated by the Board in a future rate hearing.

Accounting Entries

1. To record the ratepayer share of net revenues from electric DSM:

Debit:	Other income	(Account 319. 010)
Credit:	Operating & Maintenance	(Various accounts)
Credit:	2011 EPESDA	(Account 179. 601)

To record the ratepayer share of net revenues generated by providing DSM services to electric LDCs.

2. Interest accrual:

Debit:	Interest expense	(Account 323. 000)
Credit:	Interest on 2011 EPESDA	(Account 179. 611)

To record simple interest on the opening monthly balance of the 2011 EPESDA using the Board approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR A
GAS DISTRIBUTION ACCESS RULE COSTS DEFERRAL ACCOUNT
("2011 GDARCDA")

For the 2011 Fiscal Year
(January 1, 2011 to December 31, 2011)

The purpose of the 2011 GDARCDA is to record all incremental unbudgeted capital and operating costs associated with the development, implementation, and operation of the Gas Distribution Access Rule. Such costs would include, but not be limited to, market restructuring oriented customer education and communication programs, legal or expert advice required, operating costs in relation to the establishment of contractual agreements and developing revised business processes and related computer hardware and software required to meet the requirements of the GDAR.

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner to be designated by the Board in a future rate hearing.

Accounting Entries

1. To record costs related to Gas Distribution Access Rule requirements:

Debit:	2011 GDARCDA	(Account 179. 201)
Credit:	Accounts payable	(Account 251. 010)

To record the unbudgeted costs associated with GDAR development, implementation, and operation.

2. Interest accrual:

Debit:	Interest on 2011 GDARCDA	(Account 179. 211)
Credit:	Interest expense	(Account 323. 000)

To record simple interest on the opening monthly balance of the 2011 GDARCDA using the Board approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR A
MANUFACTURED GAS PLANT DEFERRAL ACCOUNT
("2011 MGPDA")

For the 2011 Fiscal Year
(January 1, 2011 to December 31, 2011)

The purpose of the 2011 MGPDA is to capture all costs incurred in managing and resolving issues related to the Company's manufactured gas plant ("MGP") legacy operations. Amounts recorded in the 2010 MGPDA will also be transferred to the 2011 MGPDA. Costs charged to the account could include, but are not limited to:

- Responding to all enquiries, demands and court actions relating to former MGP sites;
- All oral and written communications with existing and former third party liability and property insurers of the Company;
- Conducting all necessary historical research and reviews to facilitate the Company's responses to all enquiries, demands, court actions and communications with claimants, third parties and insurers;
- Engaging appropriate experts (for example, environmental, insurance archivists, engineers, etc.) for the purposes of evaluating any alleged contamination that may have resulted from former MGP operations and providing advice regarding the appropriate steps to remediate/contain/monitor such contamination, if any;
- Engaging legal counsel to respond to all demands and court actions by claimants, and to take appropriate steps in relation to the Company's existing and former third party liability and property insurers; and
- Undertaking appropriate research into the regulatory treatment of costs resulting from former MGP operations in the United States.

The MGPDA would also be used to record any amounts which are payable to any claimant following settlement or trial, including any damages, interest, costs and disbursements and any recoveries from insurers or third parties.

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner to be designated by the Board in a future rate hearing.

Accounting Entries

1. To record costs:

Debit:	2011 MGPDA	(Account 179. 301)
Credit:	Accounts Payable	(Account 251. 010)
Credit:	2010 MGPDA	(Account 179. 300)

To record the unbudgeted costs incurred in managing and resolving manufactured gas plants legal proceedings and litigation and to roll forward any un-cleared 2010 MGPDA amounts.

2. Interest accrual:

Debit:	Interest on 2011 MGPDA	(Account 179. 311)
Credit:	Interest expense	(Account 323. 000)
Credit:	Interest on 2010 MGPDA	(Account 179. 310)

To record simple interest on the opening monthly balance of the 2011 MGPDA using the Board approved EB-2006-0117 interest rate methodology and to roll forward any un-cleared interest amounts on the 2010 MGPDA.

ACCOUNTING TREATMENT FOR A
MUNICIPAL PERMIT FEES DEFERRAL ACCOUNT
("2011 MPFDA")

For the 2011 Fiscal Year
(January 1, 2011 to December 31, 2011)

The purpose of the 2011 MPFDA is to capture the revenue requirement impact from Municipal permit fees charged for certain activities, such as road cuts, related to the Company's construction and maintenance operations. These are unbudgeted new charges being incurred by the Company, imposed by Municipal governments in Ontario, resulting from changes to Ontario regulations made under the Municipal Act, 2001.

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner to be designated by the Board in a future rate hearing.

Accounting Entries

1. To record Municipal permit fee costs:

Debit:	2011 MPFDA	(Account 179. 541)
Credit:	Accounts Payable	(Account 251. 010)

To record the permit fee costs incurred in construction and maintenance operations.

2. Interest accrual:

Debit:	Interest on 2011 MPFDA	(Account 179. 551)
Credit:	Interest expense	(Account 323. 000)

To record simple interest on the opening monthly balance of the 2011 MPFDA using the Board approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR AN
ONTARIO HEARING COSTS VARIANCE ACCOUNT
("2011 OHCVA")

For the 2011 Fiscal Year
(January 1, 2011 to December 31, 2011)

The purpose of the 2011 OHCVA is to record the variance between the actual costs incurred by the Company in relation to 2011 regulatory proceedings, stakeholder consultatives, Board costs, and related expenses versus the $5,842,500 which is embedded within rates.

Simple interest is to be calculated on the opening monthly balance of the 2011 OHCVA using the Board approved EB-2006-0117 interest rate methodology. The balance of the OHCVA, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

Accounting Entries

1. To record the variance in Ontario proceeding related costs:

Debit:	2011 OHCVA	(Account 179. 221)
Credit:	Accounts payable	(Account 251. 010)
	or	
Debit:	Operating revenue	(Account 300. 000)
Credit:	2011 OHCVA	(Account 179. 221)

To record variances between actual Ontario proceeding related costs and the amount embedded in rates.

2. Interest accrual:

Debit/Credit:	Interest on 2011 OHCVA	(Account 179. 231)
Credit/Debit:	Interest expense	(Account 323. 000)

To record simple interest on the opening monthly balance of the 2011 OHCVA using the Board approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR AN
UNBUNDLED RATE IMPLEMENTATION COST DEFERRAL ACCOUNT
("2011 URICDA")

For the 2011 Fiscal Year
(January 1, 2011 to December 31, 2011)

The purpose of the 2011 URICDA is to record any costs, if required, of continuing with a manual solution or the costs required of an automated solution for offering Unbundled Rates 125, 300, 315 and 316. Costs to be recorded in the account include administrative, staffing, training, communication, customer education, and all other reasonably incurred costs associated with offering these rates and the additional nomination windows required for such rates.

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner to be designated by the Board in a future rate hearing.

Accounting Entries

1. To record costs related to the Unbundled Rate Implementation solution:

Debit:	2011 URICDA	(Account 179. 631)
Credit:	Accounts Payable	(Account 251. 010)

To record the costs associated with implementing Rates 125, 300, 315 and 316 through a continuing manual solution or an automated solution.

2. Interest accrual:

Debit:	Interest on 2011 URICDA	(Account 179. 641)
Credit:	Interest expense	(Account 323. 000)

To record simple interest on the opening monthly balance of the 2011 URICDA using the Board approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR AN
UNBUNDLED RATES CUSTOMER MIGRATION VARIANCE ACCOUNT
("2011 URCMVA")

For the 2011 Fiscal Year
(January 1, 2011 to December 31, 2011)

The purpose of the 2011 URCMVA is to record the revenue consequences of actual customer migration versus forecast migration for the new Unbundled Rates, 125 and 300. The pivot point or threshold for the variance account will be the revenue related to forecast migration to new rates such that if actual migration revenue is lower or higher than forecast, there would be an associated entry to the variance account to refund or collect from customers in all applicable rate classes.

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner to be designated by the Board in a future rate hearing.

Accounting Entries

1. To record the impact of customer migration to unbundled rates versus forecast:

Debit/Credit:	2011 URCMVA	(Account 179. 671)
Credit/Debit:	Operating revenue	(Account 300. 000)

To record the revenue variance associated with actual versus forecast migration of customers to unbundled rates.

2. Interest accrual:

Debit/Credit:	Interest on 2011 URCMVA	(Account 179. 681)
Credit/Debit:	Interest expense	(Account 323. 000)

To record simple interest on the opening monthly balance of the 2011 URCMVA using the Board approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR AN
AVERAGE USE TRUE-UP VARIANCE ACCOUNT
("2011 AUTUVA")

For the 2011 Fiscal Year
<u>(January 1, 2011 to December 31, 2011)</u>

The purpose of the 2011 AUTUVA is to record ("true-up") the revenue impact, exclusive of gas costs, of the difference between the forecast of average use per customer, for general service rate classes (Rate 1 and Rate 6), embedded in the volume forecast that underpins Rates 1 and 6 and the actual weather normalized average use experienced during the year. The calculation of the volume variance between forecast average use and actual normalized average use will exclude the volumetric impact of Demand Side Management programs in that year. The revenue impact will be calculated using a unit rate determined in the same manner as for the derivation of the Lost Revenue Adjustment Mechanism (LRAM), extended by the average use volume variance per customer and the number of customers.

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner to be designated by the Board in a future rate hearing.

<u>Accounting Entries</u>

1. To record the revenue impact of forecast versus normalized average use:

Debit/Credit:	2011 AUTUVA	(Account 179. 651)
Credit/Debit:	Operating revenue	(Account 300. 000)

To record the revenue impact associated with the variance in forecast average use per customer versus actual normalized average use per customer.

2. Interest accrual:

Debit/Credit:	Interest on 2011 AUTUVA	(Account 179. 661)
Credit/Debit:	Interest expense	(Account 323. 000)

To record simple interest on the opening monthly balance of the 2011 AUTUVA using the Board approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR A
TAX RATE AND RULE CHANGE VARIANCE ACCOUNT
("2011 TRRCVA")

For the 2011 Fiscal Year
(January 1, 2011 to December 31, 2011)

The purpose of the 2011 TRRCVA is to record the ratepayer portion of any variance relating to changes in actual tax rates and rules which differ from those proposed and embedded in rates. In the event that actual future tax rates and rules are not as currently expected, the Company will calculate the appropriate amounts which should be shared equally between ratepayers and the Company, based upon 2007 Board Approved base level benchmarks embedded in rates, and record the appropriate variance in the variance account to be returned to or collected from ratepayers. This true-up will occur annually, along with any associated required change to ongoing future rates.

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

Accounting Entries

1. To record the impact of actual tax rate and rule changes versus forecast:

Debit/Credit:	Operating revenue	(Account 300. 000)
Credit/Debit:	2011 TRRCVA	(Account 179. 441)

To record the ratepayer portion of any variance in taxes as a result of actual tax rates and rules differing from those proposed and embedded in rates.

2. Interest accrual:

Debit/Credit:	Interest expense	(Account 323. 000)
Credit/Debit:	Interest on 2011 TRRCVA	(Account 179. 451)

To record simple interest on the opening monthly balance of the 2011 TRRCVA using the Board approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR AN
EARNINGS SHARING MECHANISM DEFERRAL ACCOUNT
("2011 ESMDA")

For the 2011 Fiscal Year
(January 1, 2011 to December 31, 2011)

The purpose of the 2011 ESMDA is to record the ratepayer share of utility earnings that result from the application of the earnings sharing mechanism. If the 2011 actual utility return on equity, calculated on a weather normalized basis, is more than 100 basis points over the amount calculated by applying the Board's ROE Formula, the resultant amount will be shared equally (i.e., 50/50) between the Company's ratepayers and shareholders. The calculation of a utility return for earnings sharing determination purposes, will include all revenues that would otherwise be included in earnings and only those expenses (whether operating or capital) that would otherwise be allowable deductions from earnings as within a cost of service application. In addition, the following are examples of shareholder incentives and other amounts which are outside of the ambit of the earnings sharing mechanism: amounts related to the Shared Savings Mechanism ("SSM") and Lost Revenue Adjustment Mechanism ("LRAM"), amounts related to storage and transportation deferral accounts, and the Company's 50% share of tax savings calculated in association with expected tax rate and rule changes.

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

Accounting Entries

1. To record the ratepayers' share of earnings as a result of the earning sharing mechanism:

Debit:	Operating revenue	(Account 300. 000)
Credit:	2011 ESMDA	(Account 179. 581)

To record the ratepayers' share of utility earnings when the actual weather normalized ROE is greater than 100 basis points over the Board's formula ROE.

2. Interest accrual:

Debit:	Interest expense	(Account 323. 000)
Credit:	Interest on 2011 ESMDA	(Account 179. 591)

To record simple interest on the opening monthly balance of the 2011 ESMDA using the Board approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR AN
INTERNATIONAL FINANCIAL REPORTING STANDARDS TRANSITION COSTS
DEFERRAL ACCOUNT
("2011 IFRSTCDA")

For the 2011 Fiscal Year
(January 1, 2011 to December 31, 2011)

The purpose of the 2011 IFRSTCDA is to record 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.

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

Accounting Entries

1. To record incremental one-time administrative costs:

Debit:	2011 IFRSTCDA	(Account 179. 461)
Credit:	Other admin and general expense	(Account 728. ___)

To record incremental one time administrative costs in relation to converting accounting policies and processes from compliance with CGAAP to IFRS.

2. Interest accrual:

Debit:	Interest on 2011 IFRSTCDA	(Account 179. 471)
Credit:	Interest expense	(Account 323. 000)

To record simple interest on the opening monthly balance of the 2011 IFRSTCDA using the Board approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR AN
OPEN BILL SERVICE DEFERRAL ACCOUNT
("2011 OBSDA")

For the 2011 Fiscal Year
(January 1, 2011 to December 31, 2011)

The purpose of the 2011 OBSDA is to roll forward the un-cleared balances from the 2008, 2009 and 2010 OBSDA's and to accommodate the Board Approved clearance treatment. As per the EB-2009-0043 Board Accounting Order, the account includes amounts approved to be brought forward from the 2008 OBSDA and amounts incurred / recorded in 2009 for TMG consulting costs, OBA stakeholder costs and start up legal costs. An equal amount of the above total costs is to be shared equally by ratepayers and EGD over the years 2010 through 2012.

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

Accounting Entries

1. To track the amount of the OBSDA costs for clearance in 2010 through 2012:

Debit:	2011 OBSDA	(Account 179. 421)
Credit:	2010 OBSDA	(Account 179. 420)

To track costs relating to Open Bill Services program.

2. Interest accrual:

Debit:	Interest on 2011 OBSDA	(Account 179. 431)
Credit:	Interest on 2010 OBSDA	(Account 179. 430)
Credit:	Interest expense	(Account 323. 000)

To record simple interest on the opening monthly balance of the 2011 OBSDA using the Board approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR AN
OPEN BILL ACCESS VARIANCE ACCOUNT
("2011 OBAVA")

For the 2011 Fiscal Year
January 1, 2011 to December 31, 2011)

The purpose of the 2011 OBAVA is to roll forward the un-cleared balance from the 2008, 2009 and 2010 OBAVA's and to accommodate the Board Approved clearance treatment. As per the EB-2009-0043 Board Accounting Order, the amount originally recorded in the 2008 OBAVA was to be rolled forward to 2009 and subsequent year accounts, to be shared equally between the Company and ratepayers, and to be disposed of in equal increments over the years 2010 through 2012.

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

Accounting Entries

1. To roll forward un-cleared OBAVA amounts:

Debit:	2011 OBAVA	(Account 179. 521)
Credit:	2010 OBAVA	(Account 728. 520)

To track costs relating to Open Bill Access program.

2. Interest accrual:

Debit:	Interest on 2011 OBAVA	(Account 179. 531)
Credit:	Interest on 2010 OBAVA	(Account 179. 530)
Credit:	Interest expense	(Account 323. 000)

To record simple interest on the opening monthly balance of the 2011 OBAVA using the Board approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR AN
OPEN BILL REVENUE VARIANCE ACCOUNT
("2011 OBRVA")

For the 2011 Fiscal Year
(January 1, 2011 to December 31, 2011)

The purpose of the 2011 OBRVA is to track and record the net revenue for Open Bill Services. The account allows for net annual revenue amounts in excess of $7.389 million to be shared 50/50 with ratepayers, and allows for a credit to Enbridge in the event that net annual revenues are less than $4.889 million, equal to the shortfall between actual net revenues and $4.889 million. The net revenue amounts will be determined in accordance with the EB-2009-0043 Board Approved Open Bill Access Settlement Proposal dated October 15, 2009.

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

Accounting Entries

1. To track and record Open Bill services net revenue:

Debit/Credit:	2011 OBRVA	(Account 179. 481)
Credit/Debit:	Other income	(Account 319. 010)

To record net revenue associated with Open Bill Service programs.

2. Interest accrual:

Debit/Credit:	Interest on 2011 OBRVA	(Account 179. 491)
Credit/Debit:	Interest expense	(Account 323. 000)

To record simple interest on the opening monthly balance of the 2011 OBRVA using the Board approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR AN
EX-FRANCHISE THIRD PARTY BILLING SERVICES DEFERRAL ACCOUNT
("2011 EFTPBSDA")

For the 2011 Fiscal Year
(January 1, 2011 to December 31, 2011)

The purpose of the 2011 EFTPBSDA is to record and track revenues generated from third party billing services provided to ex-franchise parties net of incremental costs associated with the services. The net revenue is to be shared on a 50/50 basis with ratepayers. The net revenue amounts will be determined in accordance with the EB-2009-0043 Board Approved Open Bill Access Settlement Proposal dated October 15, 2009.

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

Accounting Entries

1. To track and record net revenue:

Debit/Credit:	2011 EFTPBSDA	(Account 179. 081)
Credit/Debit:	Various accounts	(Account ___. ___)

To record net revenue associated with Ex-Franchise third party Billing Services.

2. Interest accrual:

Debit/Credit:	Interest on 2011 EFTPBSDA	(Account 179. 091)
Credit/Debit:	Interest expense	(Account 323. 000)

To record simple interest on the opening monthly balance of the 2011 EFTPBSDA using the Board approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR A MEAN DAILY VOLUME MECHANISM DEFERRAL ACCOUNT (“2011 MDVMDA”)

For the 2011 Fiscal Year
(January 1, 2011 to December 31, 2011)

The purpose of the 2011 MDVMDA is to record the incremental costs of establishing and implementing the changes required to meet the Company’s newly proposed Mean Daily Volume mechanism. The Company was ordered to bring forward a proposed mechanism for future adoption in the Board’s Decision and Order in the Commodity, Load Balancing and Cost Allocation proceeding (EB-2008-0106).

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner designated by the Board in a future rate hearing.

Accounting Entries

1. To record incremental costs:

Debit:	2011 MDVMDA	(Account 179. 561)
Credit:	Accounts payable	(Account 251. 010)

To record the incremental costs of establishing and implementing the Company’s proposed Mean Daily volume mechanism.

2. Interest accrual:

Debit:	Interest on 2011 MDVMDA	(Account 179. 571)
Credit:	Interest expense	(Account 323. 000)

To record simple interest on the opening monthly balance of the 2011 MDVMDA using the Board approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR A
DEMAND SIDE MANAGEMENT VARIANCE ACCOUNT
("2011 DSMVA")

For the 2011 Fiscal Year
(January 1, 2011 to December 31, 2011)

The purpose of the 2011 DSMVA is to record the difference between the actual 2011 DSM spending and the $26.7 million incorporated within 2011 rates. Any amount of under spending will be incorporated into the DSMVA, but overspending will be capped at 15% of the DSM budget dependent upon the Company achieving more than the 2011 DSM targeted TRC Net Benefits, on a pre-audited basis, as determined in the EB-2006-0021 proceeding. Furthermore, overspending charged to the 2011 DSMVA is limited to incremental program expenses only.

As part of the Company's 2011 Amended Low Income Weatherization Plan submission in EB-2010-0175, the Company has requested an additional $1.367 million in program spending. If approved, the additional spending will be recorded within the DSMVA. The Company would also be able to charge the DSMVA for further additional funding, of up to 15% of the amended Low Income Weatherization budget, once the program has achieved 100% of its total overall scorecard, without the pre-requisite of achievement of its 2011 TRC net benefits target.

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner to be designated by the Board in a future rate hearing.

Accounting Entries

1. To record variances in variable costs only:

Debit/Credit:	2011 DSMVA	(Account 179. 061)
Credit/Debit:	Operating & Maintenance	(Various accounts)

To record the difference between actual and forecast Demand Side Management operating expenditures.

2. To record additional program spending:

Debit:	2011 DSMVA	(Account 179. 061)
Credit:	Accounts payable	(Account 251. 010)

To record additional program spending as per the Company's 2011 Amended Low Income Weatherization Plan (EB-2010-0175).

3. Interest accrual:

Debit/Credit:	Interest on 2011 DSMVA	(Account 179. 071)
Credit/Debit:	Interest expense	(Account 323. 000)

To record simple interest on the opening monthly balance of the 2011 DSMVA using the Board approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR A
LOST REVENUE ADJUSTMENT MECHANISM
("2011 LRAM")

For the 2011 Fiscal Year
(January 1, 2011 to December 31, 2011)

The purpose of the 2011 LRAM is to record the amount of distribution margin gained or lost when the Company's DSM programs are less or more successful than budgeted, for the period January 1, 2011 to December 31, 2011.

When the utility's DSM programs, are less successful in the Test Year than budgeted, the utility gains distribution margin. Similarly, the utility loses distribution margin in the Test Year when its DSM programs are more successful than budgeted.

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner to be designated by the Board in a future rate hearing.

Accounting Entries

1. To record LRAM amounts:

Debit/Credit:	Gas costs	(Account 623. 010)
Credit/Debit:	2011 LRAM	(Account 179. 101)

To record in the LRAM, the distribution margin impact of differences between actual and budget gas savings forecast in the Company's DSM programs.

2. Interest accrual:

Debit/Credit:	Interest expense	(Account 323. 000)
Credit/Debit:	Interest on 2011 LRAM	(Account 179. 111)

To record simple interest on the opening monthly balance of the 2011 LRAM using the Board approved EB-2006-0117 interest rate methodology.

ACCOUNTING TREATMENT FOR A
SHARED SAVINGS MECHANISM VARIANCE ACCOUNT
(“2011 SSMVA”)

For the 2011 Fiscal Year
(January 1, 2011 to December 31, 2011)

The purpose of the 2011 SSMVA is to record the actual amount of the shareholder incentive earned by the Company as a result of its DSM programs. The criteria and formula used to determine the amount of any shareholder incentive, to be recorded in the SSMVA, will be in accordance with the guidelines established in the generic DSM proceeding EB-2006-0021 and 2011 DSM Plan proceeding EB-2010-0175.

Simple interest is to be calculated on the opening monthly balance of this account using the Board approved EB-2006-0117 interest rate methodology. The balance of this account, together with carrying charges, will be disposed of in a manner to be designated by the Board in a future rate hearing.

Accounting Entries

1. Shareholder incentive earned by the Company related to DSM programs:

Debit:	2011 SSMVA	(Account 179. 281)
Credit:	Other income	(Account 319. 010)

To record the shareholder incentive earned by the Company related to its DSM programs.

2. Interest accrual:

Debit:	Interest on 2011 SSMVA	(Account 179. 291)
Credit:	Interest expense	(Account 323. 000)

To record simple interest on the opening monthly balance of the 2011 SSMVA using the Board approved EB-2006-0117 interest rate methodology.

APPENDIX “E”

Final Issues List
(Procedural Order No. 2, dated October 28, 2010)

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2010-0146

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

AND IN THE MATTER OF an Application by Enbridge Gas Distribution Inc. for an Order or Orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas commencing January 1, 2011.

PROCEDURAL ORDER NO. 2

Enbridge Gas Distribution Inc. ("Enbridge" or the "Applicant") filed an Application on September 1, 2010 with the Ontario Energy Board (the "Board") under section 36 of the *Ontario Energy Board Act, 1998*, S.O. c.15, Sched. B, as amended, for an order of the Board approving or fixing rates for the distribution, transmission and storage of natural gas, effective January 1, 2011. The Board assigned file number EB-2010-0146 to the Application and has issued a Notice of Application dated September 13, 2010 (the "Notice").

Procedural Order No. 1 established the procedural schedule for the hearing and included a Draft Issues List. The Board requested comments on the Draft Issues List by October 21, 2010. Enbridge, Just Energy, Jason Stacey and Comsatec Inc. provided submissions. Enbridge filed its reply on October 25, 2010.

Enbridge requested that the Board re-phrase Draft Issues List number 12 (pertaining to the Tax Rate and Rule Change Variance Account) to more narrowly focus the issue. The reason given was that the language in the Draft Issues List goes beyond what is at issue which is the proposed adjustment to the 2010 tax variance account. The Board approves Enbridge's request and will re-phrase it as requested, as follows:

> Is the adjustment calculated for the 2010 Tax Rate and Rule Change Variance Account (“TRRCVA”) appropriate?

Just Energy requested that the Board add the following issue to the issues list:

> Is the proposed increase in Direct Purchase Administration Charge (“DPAC”) appropriate?

The Board notes that Enbridge did not object to Just Energy’s request. The Board therefore approves of adding the issue.

Jason Stacey requested that the Board add an “Other Issues” category to the issues list to capture new issues that arise in the proceeding. Mr. Stacey also requested placement of a more specific issue about clarifying some language in the Company’s Rate Handbook. Enbridge submitted that Mr. Stacey’s issue could be narrowed to focus on the discrete issue he raised in respect of the Rate Handbook language for Rider H – Balancing Service Rider. Enbridge proposed wording for this issue. The Board believes Mr. Stacey’s concerns can be addressed within the scope of the wording as proposed by Enbridge. The Board will approve the addition of the issue with the wording as proposed by Enbridge, as follows:

> Is it appropriate to clarify the wording in Rider H of the Rate Handbook related to the In Franchise Title Transfer Service charges?

With respect to Comsatec’s request to add an issue concerning billing requirements for customers taking firm and interruptible service but measured with only one meter, Enbridge objected to adding the issue on the basis that there is no impropriety in the manner in which its billing practices are carried out for firm and interruptible customers. Enbridge said this appears to be a customer-specific consumption issue and that the appropriate time to raise it is at the customer’s annual contract renewal when the customer’s contract parameters are re-established.

The Board agrees with Enbridge that this proceeding is not the appropriate place to deal with the matter raised by Comsatec. The Board expects that the matter will be dealt with in accordance with Enbridge’s usual practice at the time the contracts are renewed. The Board will therefore not add this issue to the issues list.

The Final Issues List is attached to this order.

Please be aware that further procedural orders may be issued from time to time.

THE BOARD ORDERS THAT:

1. The Final Issues List is attached as Appendix “A” to this procedural order.

2. All filings to the Board must quote file number EB-2010-0146 and consist of two paper copies and one electronic copy in searchable / unrestricted PDF format filed through the Board’s web portal at www.errr.oeb.gov.on.ca. Filings must clearly state the sender’s name, postal address and telephone number and, if available, a fax number and e-mail address. Please use the document naming conventions and document submission standards outlined in the RESS Document Guideline found on the “e-Filing Services” webpage of the Board’s website at www.oeb.gov.on.ca. If the web portal is not available you may email your document to BoardSec@oeb.gov.on.ca. With respect to distribution lists for all electronic correspondence and materials related to this proceeding, parties must include the Case Manager, Colin Schuch at colin.schuch@oeb.gov.on.ca and Senior Legal Counsel, Kristi Sebalj at Kristi.sebalj@oeb.gov.on.ca

DATED at Toronto, October 28, 2010
ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

APPENDIX A

Final Issues List

Enbridge 2011 Rates - EB-2010-0146

1. Has Enbridge calculated its proposed distribution revenue requirement, including the assignment of that revenue requirement to the rate classes and the resulting rates, in accordance with the EB-2007-0615 incentive settlement agreement?

2. Is the forecast of degree days appropriate?

3. Is the forecast of average use appropriate?

4. Is the forecast of customer additions appropriate?

5. Is the gas volume budget appropriate?

Y FACTORS

6. Is the amount proposed for the Y factor Power Generation Projects appropriate?

7. Is the amount proposed for the Y factor DSM Program appropriate?

8. Is the amount proposed for the Y factor for CIS/Customer Care appropriate?

9. Is the amount proposed for the Y factor - Gas Cost & Carrying Cost appropriate?

DEFERRAL AND VARIANCE ACCOUNTS

10. Is it appropriate to establish for 2011 the previously agreed upon list of deferral and variance accounts from the Settlement Agreement in the EB-2007-0615 proceeding, updated to include additional approved accounts as identified in the Company's 2010 rates proceeding (EB-2009-0172)?

11. Is it appropriate to discontinue for 2011 the Change in Purchased Gas Variance Disposition Methodology DA (“CPGVDMDA”)?

12. Is the adjustment calculated for the 2010 Tax Rate and Rule Change Variance Account (“TRRCVA”) appropriate? (ref: C/1/2)

OTHER ISSUES

13. Is the proposed increase in Direct Purchase Administration Charge (“DPAC”) appropriate?

14. Is it appropriate to clarify the wording in Rider H of the Rate Handbook related to the In Franchise Title Transfer Service charges?

IMPLEMENTATION

15. How should the new rates be implemented?

APPENDIX “F”

Settlement Agreement
(Dated November 23, 2010)

SETTLEMENT AGREEMENT

November 23, 2010

TABLE OF CONTENTS

12 Is the adjustment calculated for the 2010 Tax Rate and Rule Change Variance Account ("TRRCVA") appropriate? (ref: C/1/2)

13 Is the proposed increase in Direct Purchase Administration Charge ("DPAC") appropriate?

14 Is it appropriate to clarify the wording in Rider H of the Rate Handbook related to the In Franchise Title Transfer Service charges?

15 How should the new rates be implemented?

PREAMBLE

This Settlement Agreement is filed with the Ontario Energy Board (the “Board") in connection with the application of Enbridge Gas Distribution Inc. (“Enbridge”), for an order or orders approving or fixing rates for the sale, distribution, transmission, and storage of gas for 2011.

In Procedural Order No. 1, the Board established the process to address Enbridge’s application. The Issues List for this proceeding was established in Procedural Order No. 1 and was updated in Procedural Order No. 2.

A Settlement Conference was held on November 17, 2010. Mr. Ken Rosenberg acted as facilitator for the Settlement Conference. This Settlement Agreement arises from the Settlement Conference.

Enbridge and the following intervenors, as well as Ontario Energy Board technical staff (“Board Staff”), participated in the Settlement Conference:

BUILDING OWNERS AND MANAGERS ASSOCIATION OF THE GREATER TORONTO AREA (“BOMA”)
CANADIAN MANUFACTURERS & EXPORTERS (“CME”)
CONSUMERS COUNCIL OF CANADA (“CCC”)
DIRECT ENERGY MARKETING LIMITED (“DE”)
ENERGY PROBE RESEARCH FOUNDATION (“ENERGY PROBE”)
FEDERATION OF RENTAL-HOUSING PROVIDERS OF ONTARIO (“FRPO”)
INDUSTRIAL GAS USERS ASSOCIATION (“IGUA”)
JASON STACEY, NATURAL GAS SPECIALIST
JUST ENERGY ONTARIO L.P. (“JUST ENERGY”)
ONTARIO ASSOCIATION OF PHYSICAL PLANT ADMINISTRATORS (“OAPPA”)
SCHOOL ENERGY COALITION (“SEC”)
TRANSCANADA ENERGY LTD. (“TransCanada Energy”)
VULNERABLE ENERGY CONSUMER’S COALITION (“VECC”)

The Settlement Agreement deals with all of the issues listed at Appendix “A” to the Board’s Procedural Order #2, dated October 28, 2010 (the "Issues List").

The description of each issue assumes that all parties participated in the negotiation of the issue, unless specifically noted otherwise. Board Staff takes no position on any issue and, as a result, is not a party to the Settlement Agreement.

It is acknowledged and agreed that none of the completely settled provisions of this Settlement Agreement is severable. If the Board does not, prior to the commencement of the hearing of the evidence in this proceeding, accept the provisions of the Settlement

Agreement in their entirety, there is no Settlement Agreement (unless the parties agree that any portion of the Settlement Agreement that the Board does accept may continue as a valid Settlement Agreement).

Best efforts have been made to identify all of the evidence that relates to each settled issue. The supporting evidence for each settled issue is identified individually by reference to its exhibit number in an abbreviated format; for example, Exhibit B, Tab 3, Schedule 1 is referred to as B-3-1. The identification and listing of the evidence that relates to each settled issue is provided to assist the Board.

The Settlement Agreement describes the agreements reached on the issues. The Settlement Agreement provides a direct link between each settled issue and the supporting evidence in the record to date. In this regard, the parties are of the view that the evidence provided is sufficient to support the Settlement Agreement in relation to the settled issues and, moreover, that the quality and detail of the supporting evidence, together with the corresponding rationale, will allow the Board to make findings agreeing with the proposed resolution of the settled issues. In the event that the Board does not accept the proposed settlement of any issue, further evidence may be required on the issue for the Board to consider it fully.

According to the Board's *Settlement Conference Guidelines* (p. 3), the parties must consider whether a settlement proposal should include an appropriate adjustment mechanism for any settled issue that may be affected by external factors. Enbridge and the other parties who participated in the Settlement Conference consider that no settled issue requires an adjustment mechanism other than those expressly set forth herein.

None of the parties can withdraw from the Settlement Agreement except in accordance with Rule 32 of the *Ontario Energy Board Rules of Practice and Procedure*. Finally, unless stated otherwise, a settlement of any particular issue in this proceeding is without prejudice to the positions parties might take with respect to the same issue in future proceedings during the term of Enbridge's current five year Incentive Regulation ("IR") plan, or thereafter.

OVERVIEW

In the EB-2007-0615 proceeding, the Board approved a settlement agreement that prescribes the rate setting approach to be used by Enbridge over the five year Incentive Regulation term from 2008 to 2012.[1] This approach involves the use of a Distribution Revenue Requirement per Customer Formula (the "Adjustment Formula") to adjust the amount to be recovered in rates for each year of the IR term.

[1] EB-2007-0615, Exhibit N1, Tab 1, Schedule 1.

The IR Settlement Agreement requires Enbridge to file prescribed information by October 1st each year, for the purpose of setting rates for the following year. This information is used in the Adjustment Formula to determine the Distribution Revenue Requirement (the "DRR") for the following year. As part of the filing, the Company also sets out the Total Revenue Requirement to be recovered and the allocation of the DRR to its rate classes, and a rate handbook and supporting documentation detailing how rates have been adjusted.

As set out in this Settlement Agreement, the parties have reached a full settlement of all issues. The resulting average rate impact will be 0.5% or less for all customer classes on a T-service basis (that is, excluding commodity costs).

THE ISSUES

1 Has Enbridge calculated its proposed distribution revenue requirement, including the assignment of that revenue requirement to the rate classes and the resulting rates, in accordance with the EB-2007-0615 incentive settlement agreement?

For the purposes of settling the issues in this proceeding, all parties, except those noted below, agree that Enbridge has calculated its proposed distribution revenue requirement including the assignment of that revenue requirement to the rate classes and resulting rates in accordance with the EB-2007-0615 incentive settlement agreement.[2]

DE, Just Energy and TransCanada Energy take no position on the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

B-1-1	Rate Adjustment Summary
B-1-2	2010 Revenue per Customer Cap Determination
B-1-3	Inflation Factor
B-1-4	Customer Additions
B-1-5	Gas Volume Budget
B-1-6	Budget Degree Days
B-1-7	Average Use and Economic Assumptions
B-2-1	Y Factor – Power Generation Projects
B-2-2	Y Factor – DSM Program
B-2-3	Y Factor – CIS/Customer Care Cost
B-2-4	Y Factor – Gas Cost & Carrying Cost

[2] Note that the settlement described under Issue 13, below, has an effect on the amount of the distribution revenue requirement to be recovered through distribution revenues, but it does not impact the level of distribution revenue requirement, which remains at $988.6 million (Exhibit B, Tab 1, Schedule 2, Page 1, Row 24, Col. 1). As a result of the settlement of Issue 13, the amount of the distribution revenue requirement that will be recovered through distribution revenues rather than DPAC and System Gas Administration Fee revenues is approximately $276 thousand. The impact of this on distribution rates is minuscule.

B-3-1	2011 Proposed Rates
B-3-2	Rate Schedules
B-3-3	2010 Revenues by Rate Class
B-3-4	Proposed Volumes and Revenue Recovery by Rate Class
B-3-5	Proposed Billed and Unbilled Revenue
B-3-6	Summary of Proposed Rate Change by Rate Class
B-3-7	Calculation of Gas Supply Charges by Rate Class
B-3-8	Detailed Revenue Calculations
B-3-9	Annual Bill Comparison EB-2010-0146 vs EB-2010-0258
B-3-10	Assignment of Revenue Requirement
B-4-1	Gas Cost, Transportation and Storage
B-4-2	Gas Cost Schedules
I-1-1	Board Staff Interrogatory #1
I-2-1	BOMA Interrogatory #3
I-4-11 to 13	FRPO Interrogatories #11 to 13
I-6-2 to 8	TCE Interrogatories #2 to 8
I-7-1- 2 and 9-13 and17-18	VECC Interrogatories #1, 2 and 9 to 13 and 17 to 18

2 Is the forecast of degree days appropriate?

For the purposes of settling the issues in this proceeding, all parties, except those noted below, agree that the forecast of degree days is appropriate.

DE, Just Energy and TransCanada Energy take no position on the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

B-1-6	Budget Degree Days
I-4-6 to 8	FRPO Interrogatories #6 to 8

3 Is the forecast of average use appropriate?

For the purposes of settling the issues in this proceeding, all parties, except those noted below, agree that the forecast of average use is appropriate.

DE, Just Energy and TransCanada Energy take no position on the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

B-1-7	Average Use and Economic Assumptions
I-4-9 to 10	FRPO Interrogatories #9 and 10
I-7-6	VECC Interrogatory #6

4 Is the forecast of customer additions appropriate?

For the purposes of settling the issues in this proceeding, all parties, except those noted below, agree that the forecast of customer additions is appropriate.

DE, Just Energy and TransCanada Energy take no position on the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

B-1-4	Customer Additions
I-1-2	Board Staff Interrogatory #2
I-7-3	VECC Interrogatory #3

5 Is the gas volume budget appropriate?

For the purposes of settling the issues in this proceeding, all parties, except those noted below, agree that the gas volume budget is appropriate.

DE, Just Energy and TransCanada Energy take no position on the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

B-1-5	Gas Volume Budget
B-3-7	Calculation of Gas Supply Charges by Rate Class
B-4-1	Gas Cost, Transportation and Storage
B-4-2	Gas Cost Schedules
I-1- 3	Board Staff Interrogatory # 3
I-4-1 to 5	FRPO Interrogatories #1 to 5
I-7-4 to 5	VECC Interrogatories #4 and 5

6 Is the amount proposed for the Y factor Power Generation Projects appropriate?

For the purposes of settling the issues in this proceeding, all parties, except those noted below, agree that the amount proposed for the Y factor Power Generation Projects is appropriate.

DE, Just Energy and TransCanada Energy take no position on the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

B-2-1	Y Factor – Power Generation Projects
I-2-2	BOMA Interrogatory #2
I-6-1	TCE Interrogatory #1

7 Is the amount proposed for the Y factor DSM Program appropriate?

For the purposes of settling the issues in this proceeding, all parties, except those noted below, agree that the amount proposed for the Y factor DSM Program is appropriate.

DE, Just Energy and TransCanada Energy take no position on the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

B-2-2	Y Factor – DSM Program
I-1-4	Board Staff Interrogatory #4
I-2-1 and 3	BOMA Interrogatories #1 and 3
I-7-7	VECC Interrogatory #7

8 Is the amount proposed for the Y factor for CIS/Customer Care appropriate?

For the purposes of settling the issues in this proceeding, all parties, except those noted below, agree that the amount proposed for the Y factor for CIS and Customer Care is appropriate.

DE, Just Energy and TransCanada Energy take no position on the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

B-2-3	Y Factors – CIS/Customer Care Cost
E-2-1	Customer Care and CIS Settlement Template

9 Is the amount proposed for the Y factor – Gas Cost & Carrying Cost appropriate?

For the purposes of settling the issues in this proceeding, all parties, except those noted below, agree that the amount proposed for the Y factor for Gas Cost and related carrying costs is appropriate.

DE, Just Energy and TransCanada Energy take no position on the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

B-2-4	Y Factor – Gas Cost & Carrying Cost
B-4-1	Gas Cost, Transportation and Storage
B-4-2	Gas Cost Schedules

10 Is it appropriate to establish for 2011 the previously agreed upon list of deferral and variance accounts from the Settlement Agreement in the EB-2007-0615 proceeding, updated to include additional approved accounts as identified in the Company's 2010 rates proceeding (EB-2009-0172)?

For the purposes of settling the issues in this proceeding, all parties, except those noted below, agree that it is appropriate to establish for 2011 the previously agreed upon list of deferral and variance accounts from the Settlement Agreement in the EB-2007-0615 proceeding, as well as the additional approved accounts as identified in the Company's 2010 rates proceeding (EB-2009-0172).

DE, Just Energy and TransCanada Energy take no position on the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

B-5-1	Deferral & Variance Accounts – Actual Balances
C-1-1	Deferral & Variance Accounts
I-7-15,17 and 18	VECC Interrogatories #14 to 16

11 Is it appropriate to discontinue for 2011 the Change in Purchased Gas Variance Disposition Methodology DA ("CPGVDMDA")?

For the purposes of settling the issues in this proceeding, all parties, except those noted below, agree that it is appropriate to discontinue the CPGVDMDA for 2011.

DE, Just Energy and TransCanada Energy take no position on the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

B-7-1	Deferral & Variance Accounts – Actual Balances
C-1-1	Deferral & Variance Accounts

12 Is the adjustment calculated for the 2010 Tax Rate and Rule Change Variance Account ("TRRCVA") appropriate? (ref: C/1/2)

For the purposes of settling the issues in this proceeding, all parties, except those noted below, agree that the adjustment calculated for the 2010 TRRCVA is appropriate.

DE, Just Energy and TransCanada Energy take no position on the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

B-7-1	Deferral & Variance Accounts – Actual Balances
C-1-1	Deferral & Variance Accounts
C-1-2	Update of Sharing of Tax Change Savings Forecast Amounts

13 Is the proposed increase in Direct Purchase Administration Charge ("DPAC") appropriate?

For the purposes of settling the issues in this proceeding, all parties, except those noted below, have reached the following agreement with respect to the DPAC and the System Gas Administration Fee:

(a) the DPAC will remain unchanged at 2010 levels (monthly fixed charge of $75 per pool and monthly account charge of $0.21 per account) for the duration of Enbridge's five year Incentive Regulation term (fiscal years 2011 and 2012);

(b) the System Gas Administration Fee will remain unchanged at the 2010 level of 0.0224 c/m^3 for the duration of Enbridge's five year Incentive Regulation term (fiscal years 2011 and 2012); and

(c) prior to filing the next IR rebasing application with the Board, Enbridge will facilitate a meeting with interested stakeholders to engage in discussion with Enbridge about the DPAC.

IGUA and TransCanada Energy take no position on the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

B-3-1	2011 Proposed Rates
B-3-2	Rate Handbook
I-3-1	Direct Energy Interrogatory #1
I-5-1 to 3	Just Energy Interrogatories #1 to 3

14 Is it appropriate to clarify the wording in Rider H of the Rate Handbook related to the In Franchise Title Transfer Service charges?

For the purposes of settling the issues in this proceeding, all parties, except those noted below, agree that clarifying wording as shown in Appendix A to this Settlement Agreement will be included in Rider H of the Rate Handbook.

DE, Just Energy and TransCanada Energy take no position on the proposed settlement of this issue.

Evidence: The evidence in relation to this issue includes the following:

B-3-1	2011 Proposed Rates
B-3-2	Rate Handbook

15 How should the new rates be implemented?

For the purposes of settling the issues in this proceeding, all parties agree that Enbridge will implement the new 2011 rates arising from this Settlement Agreement on January 1, 2011. In the event that, due to unforeseen circumstances, Enbridge is not able to implement the new 2011 rates on January 1, 2011, all parties agree that Enbridge is entitled to recover the full year impact of the rate changes arising from this Settlement Agreement, regardless of the timing of the implementation of the new rates.

Evidence: The evidence in relation to this issue includes the following:

A-3-1	Approvals Requested

Just Energy and TransCanada Energy take no position on the proposed settlement of this issue.

RIDER: H	BALANCING SERVICE RIDER

APPLICABILITY:

This rider is applicable to any Applicant who enters into Gas Delivery Agreement with the Company under any rate.

IN FRANCHISE TITLE TRANSFER SERVICE:

In any Gas Delivery Agreement between the Company and the Applicant, an Applicant may elect to initiate a transfer of natural gas from one of its pools to the pool of another Applicant for the purposes of reducing an imbalance between the Applicant's deliveries and consumption as recorded in its Banked Gas Account or Cumulative Imbalance Account. Elections must be made in accordance with the Company's policies and procedures related to transaction requests under the Gas Delivery Agreement.

The Company will not apply an **Administration** Charge for transfers between pools that have similar Points of Acceptance (i.e. both Ontario or both Western Points of Acceptance). For transfers between pools that have dissimilar Points of Acceptance (i.e. one an Ontario and one a Western Point of Acceptance), the Company will apply the following Administration Charge per transaction to the Applicant transferring the natural gas (i.e. the seller or transferor).

Administration Charge:	$169.00	per transaction

Also, the average cost of transportation as per Rider A for the transferred volume is charged to the Applicant with a Western Point of Acceptance for transfers to an Applicant with an Ontario Point of Acceptance. The average cost of transportation as per Rider A for the transferred volume is remitted to the Applicant with a Western Point of Acceptance for transfers from an Applicant with an Ontario Point of Acceptance.

ENHANCED TITLE TRANSFER SERVICE:

In any Gas Delivery Agreement between the Company and the Applicant, the Applicant may elect to initiate a transfer of natural gas between the Company and another utility, regulated by the Ontario Energy Board, at Dawn for the purposes of reducing an imbalance between the customer's deliveries and consumption within the Enbridge Gas Distribution franchise areas. The ability of the Company to accept such an election may be constrained at various points in time for customers obtaining services under any rate other than Rate 125 or 300 due to operational considerations of the Company.

The cost for this service is separated between an Adminstration Charge that is applicable to all Applicants and a Bundled Service Charge that is only applicable to Applicants obtaining services under any rate other than Rate 125 or 300.

Administration Charge:		
Base Charge	$50.00	per transaction
Commodity Charge	$0.6622	per 10^3m^3

Bundled Service Charge:
The Bundled Service Charge shall be equal to the absolute difference between the Eastern Zone and Southwest Zone Firm Transportation tolls approved by the National Energy Board for TCPL at a 100% Load Factor.

Also, the average cost of transportation as per Rider A for the transferred volume is charged to the Applicant with a Western Point of Acceptance for transfers to another party. The average cost of transportation as per Rider A for the transferred volume is remitted to the Applicant with a Western Point of Acceptance for transfers from another party.

GAS IN STORAGE TITLE TRANSFER:

An Applicant that holds a contract for storage services under Rate 315 or 316 may elect to initiate a transfer of title to the natural gas currently held in storage between the storage service and another storage service held by the Applicant, or any other Applicant that has contracted with the Company for storage services under Rate 315 or 316. The service will be provided on a firm basis up to the volume of gas that is equivalent to the more restrictive firm withdrawal and injection parameters of the two parties involved in the transfer. Transfer of title at rates above this level may be done on at the Company's discretion.

For Applicants requesting service between two storage service contracts that have like services, each party to the request shall pay an Administration Charge applicable to the request. Services shall be considered to be alike if the injection and deliverability rate at the ratchet levels in effect at the time of the request are the same and both services are firm or both services are interruptible. In addition to like services, the Company, at its sole discretion based on operational conditions, will also allow for the transfer of gas from a storage service contract that has a level of deliverability that is higher than the level of deliverability of the storage service contract the gas is being transfered to with only the Administration Charge being applicable to each party.

In addition to the Administration Charge, Applicants requesting service between two storage service contracts not addressed in the preceding paragraph would be subject to the injection and withdrawal charges specified in their contracts.

Administration Charge:	$25.00	per transaction