DEFERRAL AND VARIANCE ACCOUNTS

A) 2008 Test Year Approved Deferral and Variance Accounts

1. The following list represents the 2008 Board approved deferral and variance accounts ("DA" and "VA") for the 2008 fiscal year for Enbridge, divided into three groupings - Gas related, Non-Gas related, and DSM related:

Gas related DA's and VA's

1. 2008 Purchased Gas VA ("PGVA"),
2. 2008 Transactional Services DA ("TSDA"),
3. 2008 Unaccounted for Gas VA ("UAFVA"), and
4. 2008 Storage and Transportation ("S&TDA").

Non-Gas related DA's and VA's

5. 2008 Carbon Dioxide Offset Credits DA ("CDOCDA"),
6. 2008 Class Action Suit DA ("CASDA"),
7. 2008 Deferred Rebate Account ("DRA"),
8. 2008 Electric Program Earnings Sharing DA ("EPESDA"),
9. 2008 Gas Distribution Access Rule Costs DA ("GDARCDA")
10. 2008 Manufactured Gas Plant DA ("MGPDA"),
11. 2008 Municipal Permit Fees DA ("MPFDA"),
12. 2008 Ontario Hearing Costs VA ("OHCVA"),
13. 2008 Open Bill Access VA ("OBAVA"),
14. 2008 Open Bill Service DA ("OBSDA"),
15. 2008 Unbundled Rate Implementation Cost DA ("URICDA"),
16. 2008 Unbundled Rates Customer Migration VA ("URCMVA"),
17. 2008 Average Use True-Up VA ("AUTUVA"),

Witnesses: K. Culbert
A. Kacicnik
D. Small

18. 2008 Tax Rate and Rule Change VA (“TRRCVA”), and
19. 2008 Earnings Sharing Mechanism DA (ESMDA”),

DSM related DA’s and VA’s

20. 2008 Demand-Side Management VA (“DSMVA”),
21. 2008 Lost Revenue Adjustment Mechanism (“LRAM”), and
22. 2008 Shared Saving Mechanism VA (“SSMVA”).

B) Clearance of Deferral and Variance Accounts July 1, 2009

2. The following DA’s and VA’s approved to be established in various earlier proceedings, are the accounts which the Company believes it will have December 31, 2008 balances for and which can be cleared commencing July1, 2009:

a) 2008 Purchased Gas VA (“PGVA”),
b) 2008 Transactional Services DA (“TSDA”),
c) 2008 Unaccounted for Gas VA (“UAFVA”),
d) 2008 Storage & Transportation DA (“S&TDA”),
e) 2008 Carbon Dioxide Offset Credits DA (“CDOCDA”),
f) 2008 / 2009 Class Action Suit DA (“CASDA”),
g) 2008 Deferred Rebate Account (“DRA”),
h) 2008 Electric Program Earnings Sharing DA (“EPESDA”),
i) 2008 Gas Distribution Access Rule Costs DA (“GDARCDA”),
j) 2008 Municipal Permit Fees DA (“MPFDA”),
k) 2008 Ontario Hearing Costs VA (“OHCVA”),
l) 2008 Open Bill Access VA (“OBAVA”),
m) 2008 Open Bill Service DA (“OBSDA”),
n) 2008 Unbundled Rate Implementation Cost DA (“URICDA”),

Witnesses: K. Culbert
A. Kacicnik
D. Small

o) 2008 Unbundled Rates Customer Migration VA (“URCMVA”),
p) 2008 Average Use True-Up VA (“AUTUVA”),
q) 2008 Tax Rate and Rule Change VA (“TRRCVA”),
r) 2008 Earnings Sharing Mechanism DA (“ESMDA”),
s) 2007 Demand-Side Management VA (“DSMVA”),
t) 2007 Lost Revenue Adjustment Mechanism (“LRAM”), and
u) 2007 Shared Saving Mechanism VA (“SSMVA”).

3. The balances accumulated at the end of December, 2008 and to be cleared commencing July 1, 2009, will be included within the Company’s July 1, 2009 QRAM filing. As part of the July 1, 2009 deferral and variance account clearing, a one time true up of PGVA year end related variances will be analyzed and will be cleared across the appropriate types of service and customer classes.

4. Not all DA’s and VA’s have been requested for clearance:
   - The balance in the 2008 Manufactured Gas Plant DA (“MGPDA”) will be transferred into a 2009 MGPDA in order to bring forward the accumulated balance in the 2008 account. This is an ongoing matter which to date is unresolved and as a result the Company is not proposing to clear any balance related to the Manufactured Gas Plant issue at this time.
   - The following DSM-related variance accounts are expected to be the subject of clearing and/or discontinuation (if the balance is zero), subsequent to the Board’s approval of DSM audit results, the timing of which is not currently known and therefore it is unknown whether clearance could commence on July 1, 2009.
     - 2008 Demand-Side Management VA (“DSMVA”),
     - 2008 Lost Revenue Adjustment Mechanism (“LRAM”),
     - 2008 Shared Savings Mechanism VA (“SSMVA”),

Witnesses: K. Culbert
A. Kacicnik
D. Small

5. 2008 / 2009 Class Action Suit Deferral Account Treatment

   - The Class Action Suit deferral account ("CASDA") was approved within the EB-2007-0731 proceeding for recovery over a five year period commencing in 2008, the uncleared balance in the account at the end of each fiscal year is to be rolled forward into the subsequent year's CASDA deferral account until completion of clearance. That is, the 2008 CASDA ending balance will become the 2009 CASDA opening balance. Therefore, in July 2009 the Company will clear approximately one fourth of the ending balance in the 2008 CASDA.

6. A copy of the most recent available actual and forecast balances and an estimate of the potential account balances to be cleared at July 1, 2009 are included at Exhibit B, Tab 6, Schedule 1, pages 1 and 2.

C) <u>2009 Deferral and Variance Accounts Proposed</u>

- The Company has reviewed the existing, and potential requirement for, deferral or variance accounts during the incentive regulation period and the following is the list requested by the Company for the 2009 fiscal year, divided into three groupings - Gas related, Non-Gas related, and DSM related:

<u>Gas related DA's and VA's</u>

1. 2009 Purchased Gas VA ("PGVA"),
2. 2009 Transactional Services DA ("TSDA"),
3. 2009 Unaccounted for Gas VA ("UAFVA"), and
4. 2009 Storage and Transportation DA ("S&TDA").

Non-Gas related DA's and VA's

5. 2009 Carbon Dioxide Offset Credits DA ("CDOCDA"),
6. 2009 Class Action Suit DA ("CASDA"),
7. 2009 Deferred Rebate Account ("DRA"),
8. 2009 Electric Program Earnings Sharing DA ("EPESDA"),
9. 2009 Gas Distribution Access Rule Costs DA ("GDARCDA"),
10. 2009 Manufactured Gas Plant DA ("MGPDA"),
11. 2009 Municipal Permit Fees DA ("MPFDA"),
12. 2009 Ontario Hearing Costs VA ("OHCVA"),
13. 2009 Open Bill Access VA ("OBAVA"),
14. 2009 Open Bill Service DA ("OBSDA"),
15. 2009 Unbundled Rate Implementation Cost DA ("URICDA"),
16. 2009 Unbundled Rates Customer Migration VA ("URCMVA"),
17. 2009 Average Use True-Up VA ("AUTUVA"),
18. 2009 Earnings Sharing Mechanism DA ("ESMDA"), and
19. 2009 International Financial Reporting Standards DA ("IFRSCCDA").

DSM related DA's and VA's

20. 2009 Demand-Side Management VA ("DSMVA"),
21. 2009 Lost Revenue Adjustment Mechanism ("LRAM"), and
22. 2009 Shared Saving Mechanism VA ("SSMVA").

7. All 2009 deferral and variance accounts which continue over from their approval in 2008 or prior will continue to be determined / calculated in the same manner as previously established. Descriptions of the accounts will form part of the Company's draft rate order submission.

Witnesses: K. Culbert
A. Kacicnik
D. Small

D) New Deferral Accounts

8. The Company is requesting the establishment of an IFRS Conversion Costs Deferral Account ("IFRSCCDA") for the recording of conversion costs it will be incurring in order to be ready for and able to be compliant with International Financial Reporting Standards. Exhibit C, Tab 1, Schedule 2 provides more explanation of the requirement of the deferral account treatment and more details of the type of costs the Company anticipates it will incur as a result of the new Financial Reporting Standards which it will be required to adhere to. The Company would look to provide the proposed treatment of recovery of such amounts within a future fiscal year proceeding / application.

Witnesses: K. Culbert
A. Kacicnik
D. Small

INTERNATIONAL FINANCIAL REPORTING STANDARDS <u>CONVERSION COSTS DEFERRAL ACCOUNT ("IFRSCCDA")</u>

1. The Company is requesting the establishment of an IFRS Conversion Costs Deferral Account ("IFRSCCDA") in order to record the conversion costs relating to incremental operational, accounting system and IT costs which it will be incurring in order to be ready for and able to be compliant with International Financial Reporting Standards ("IFRS"). The Company will be required to adhere to IFRS within its quarterly interim and annual audited financial results by 2011. In order to achieve this ready state, the Company will be required to incur additional costs which did not form part of the base cost structure upon which its incentive regulation rate setting methodology was established. Some examples of the types of costs the Company is referring to for inclusion in this deferral account based on current expectation are:
   - incremental consulting costs;
   - incremental employee resources and related operating costs;
   - enhancements or significant alterations/additions to financial reporting and accounting systems and costs;
   - enhancements or significant alterations/additions to IT related asset costs and their related operational costs; and
   - incremental audit related costs.

   These are some examples of the types of costs the Company will be faced with but it is not necessarily an exhaustive list of costs.

2. The requested deferral account is not intended to record the financial impacts pertaining to any restatements of financial statements, but rather will capture only the incremental costs incurred relating to the broad categories indicated in the foregoing paragraph to facilitate compliance with IFRS.

Witnesses: K. Culbert
N. Kishinchandani

3. The rationale for the deferral account is that the Company is expecting the costs it incurs to be significant but is not yet in a position to accurately estimate all and/or the total magnitude of the costs. At this time, there are many unknowns surrounding the IFRS future financial reporting requirements and ultimately the relative rate and regulatory treatment which the Ontario Energy Board will have to decide upon. This is evidenced by the current IFRS consultative which the Board and Board Staff are undertaking with energy industry companies and stakeholders which is expected to evolve throughout 2009 at a minimum. The Company is seeking approval of a deferral account in which to record the above mentioned types of incremental costs of the transition which likely continue throughout 2009 and beyond. The Company is not requesting recovery of the costs at this time.

Witnesses: K. Culbert
N. Kishinchandani

SCHEDULE OF OTHER SERVICE CHARGES

1. The purpose of this evidence is to request approval for an increase in Rider G service charges for discretionary services the Company provides to customers. These services are related to gas distribution field operations services and are based upon an hourly charge-out labour rate.

2. The service charges have not been revised subsequent to the 2003 Test Year (RP-2002-0133). The approved rates were incorporated into the Company's Handbook of Rates and Distribution Charges as Rider G in EB-2003-0288, Exhibit Q2-3, Tab 4, Schedule 7.

3. The Company has operated with flat price field operation service contracts since October 1, 2004. The field operation service contracts expire on December 31, 2008. The Company has negotiated a new field operation service contract through a Request for Proposal process that initially involved 32 respondents.

4. The new field operation service contract which will be in effect January 1, 2009 includes an hourly rate increase of 9% compared to the average hourly rates from the previous field operation service contracts. The Labour Hourly Charge and each discretionary service that is structured in increments of the Labour Hourly Charge are proposed to be adjusted in accordance with the 9% hourly rate increase in the field operation service contract. Service charges not related to the Labour Hourly Charge will remain unchanged. The proposed rate adjustments are summarized in Table 1.

5. The proposed 9% increase equates to a 1.5% annual increase over the period of 2003 to 2009. The Company believes that this is an increase that falls below the inflationary factors that would impact the cost to deliver these services.

Table 1

Enbridge Miscellaneous Non- Energy Services

	Rider "G" Service Charges	Current Rate ($)	Proposed Rate ($)
1	New Account Charge	25.00	No Change
2	Appliance Activation Charge	65.00	70.00
3	Meter Unlock Charge	65.00	70.00
4	Lawyer Letter Handling Charge	15.00	No Change
5	Statement of Account Charge	10.00	No Change
6	Cheques Returned Non-Negotiable Charge	20.00	No Change
7	Red Lock Charge	65.00	70.00
8	Removal of Meter	260.00	280.00
9	Cut Off at Main	1,200.00	1,300.00
10	Valve Lock Charge	125.00 - 260.00	135.00 - 280.00
11	Safety Inspection	65.00	70.00
12	Meter Test	97.50	105.00
13	Street Service alteration	32.00	No Change
14	NGV Rental Cylinder	12.00	No Change
	Other (ad-hoc request)		
15	Labour – hourly charge	130.00	140.00
16	Cut Off at Main – commercial & special request	custom quoted	No Change
17	Cut Off at Main – other	1,200.00	1,300.00
18	Meter In-out (residential)	260.00	280.00
19	Request for Service Call Information	30.00	No Change
20	Temporary Meter Removal	260.00	280.00
21	Damage Meter Charge	360.00	380.00

Witnesses: D. Broude
A. Welburn

2009 RATE HANDBOOK REVISIONS

1. The Company is proposing revisions to its 2009 rate handbook. The proposed changes do not have an impact on the Company's proposed rates for 2009. Each of the changes have been identified in bold italic font or by revision marking mode. The Rate Handbook incorporating the proposed changes as well as the proposed rates can be found at Exhibit B, Tab 3, Schedule 2.

2. The proposed changes relate to the following:
   a) Firm Capacity on Upstream Transportation
   b) Force Majeure
   c) Rider G
   d) Late Payment Penalty
   e) Other - housekeeping

a) Firm Capacity on Upstream Transportation

3. The Company is proposing to revise the Rate Handbook to require Direct Purchase Bundled Service customers to demonstrate they have firm upstream transportation arrangements. This change can be found in the Rate Handbook at Exhibit B, Tab 3, Schedule 2 under Part IV Terms and Conditions of – Direct Purchase Arrangements, Section B – Obligation to Deliver. The rationale for this proposed change is outlined at Exhibit C, Tab 1, Schedule 8 under the Firm Capacity on Upstream Transportation evidence.

b) Force Majeure

4. The Company is proposing to change the definition of its existing Force Majeure clause which can be found in the Rate Handbook at Exhibit B, Tab 3, Schedule 2 under the Glossary of Terms at page 2 of 8 and has added a new Section O,

Witnesses: A. Kacicnik
J. Collier

entitled “Company Responsibility and Liability”, to Part III - Terms and Conditions Applicable to All Services. This section addresses the limitations on the Company’s ability to provide continuous service in the face of system safety and reliability concerns, including instances of Force Majeure. These provisions do not change the existing nature of the services provided under the Company’s rates.

5. Both the new section O and the definition of Force Majeure have been replicated to reflect the Company’s general terms and conditions contained in the Company’s service contracts. In the comparison of the service contracts to the general terms and conditions for Rates 1 and 6, the Company identified the lack of a limitation on liability provision. The Company notes that the proposed provisions are not only similar to the existing service contracts; they are similar to provisions contained in tariffs for other Canadian gas distributors, such as ATCO Gas and Terasen, and to the limitations on the guarantee of supply provisions of Ontario electric utilities as permitted by the Board’s Distribution System Code Conditions of Service, Section 2.3.1.

c) Rider G – Service Charges

6. The Company is proposing to increase the level of some service charges within its Rider G - Service Charges rate schedule. The rationale for the proposed changes to the fees is outlined in Exhibit C, Tab 1, Schedule 3 under the Schedule of Other Service Charges evidence.

d) Late Payment Penalty

7. The Company has made two changes to this section. The first identifies the effective annual interest rate applicable to the 1.5% per month late payment charge. The federal Interest Act requires that the effective annual rate be stated,

and this amendment aligns the Rate Handbook with the wording that the Company cites on customer bills for an effective annual interest rate for late payments charges.

8. The second amendment recognizes the fact that some service contracts for unbundled services set out payment terms that are different from what is set out in the general terms and conditions. These changes can be found at Exhibit B, Tab 3, Schedule 2, Part III – Terms and Conditions Applicable to all Services, Section F – Payment Conditions.

Other – Housekeeping

9. In addition to the proposed changes outlined in parts a) to d) above, the Company has made housekeeping changes to other sections throughout the Rate Handbook. These changes reflect changes to terminology or language in an effort to provide greater clarity of the Rate Handbook provisions.

Witnesses: A. Kacicnik
J. Collier

ENVISION UPDATE FOR 2006 AND 2007

1. With the filing of this report, Enbridge Gas Distribution (“Enbridge” or the “Company”) is formally requesting approval to discontinue the submission of this report on an annual basis as previously committed to in the Settlement Proposal in the 2007 rate proceeding EB-2006-0034.

2. In part, the issue at 1.6 of Exhibit N-1-1, page 17, stated:

> The Company will continue to report annually to stakeholders on the achievement of EnVision benefits in the form and the manner set out in Tables 1 and 2 in Exhibit B1/T6/S1/pp 8-9. Parties agree that unless there is a change in the overall NPV of the EnVision project, there will be no need to revisit the EnVision project in future regulatory proceedings.

3. It is the Company’s position that the EnVision project is now complete, in place and operating as designed with little prospect for the NPV of the project to change in any significant manner. As a result, the Company sees little or no benefit in continuing the tasks of tracking and reporting benefits. The Company is now requesting the discontinuation of this obligation.

Overview of the 2006 and 2007 EnVision Report

4. In compliance with the RP-2003-0203 Settlement Proposal, EGD has completed an analysis of the actual costs and benefits related to EnVision and has subsequently updated the projected costs and benefits. The costs and benefits have been summarized in Table 1 and generate a NPV of approximately $50.7M. Gain sharing for 2008 through to 2010 is undetermined at this time, but it is expected that there will be no material impact to the NPV.

Witness: D. Broude

Table 1: EnVision Cost & Benefits: Actuals 2003-2007, Forecast 2008 – 2014

	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
	ACT	ACT	ACT	ACT	ACT	FCT	FCT	FCT	FCT	FCT	FCT	FCT
Accenture Fees	6.1	21.8	21.4	13.7	12.8	12.0	12.0	8.1	6.8	6.8	6.8	1.7
Gain Sharing				0.4	0.5	Tbd	Tbd	Tbd				
IT Costs (O+M)				0.8	1.1	1.2	1.2	1.2	1.2	1.2	1.2	0.4
IT Costs (Capital)				5.0	1.7	0	3.5	1.5			1.5	0.4
Business Resources	0.3	1.7	7.9	9.5	6.3	2.8	1.8	1.7	0.7	0.3		
Total Costs	6.4	23.5	29.3	29.4	22.4	16	18.5	12.5	8.7	8.3	9.5	2.5
Operations & Engineering Benefits	0	-0.3	-9.3	-22.1	-32.8	-28.1	-28.1	-28.1	-28.1	-28.1	-28.1	-7.0
IT Cost Savings	-1.3	-2.2	-2.0	-3.6	-3.8	-3.8	-3.8	-3.8	-3.8	-3.8	-3.8	-0.9
Total Benefits	-1.3	-2.5	-11.3	-25.7	-36.6	-31.9	-31.9	-31.9	-31.9	-31.9	-31.9	-7.9
Net Costs/Benefits	5.1	21	18	3.7	-14.2	-15.9	-13.4	-19.4	-23.2	-23.6	-22.4	-5.4

5. For the years 2006 and 2007, the Budget and Actual Costs are provided in Table 2 and explained below. Cost variances for 2003 through 2005 have been previously reviewed in Exhibit B1-T6-S1 filed in EB 2006-0034.

Table 2: EnVision Cost Variances 2006 – 2007

	2006 BUD	2006 ACT	2006 VAR	2007 BUD	2007 ACT	2007 VAR
Accenture Fees	12.0	13.7	-1.7	12	12.8	-0.8
Gain Sharing	0.0	0.4	-0.4	0	0.5	-0.5
IT Costs (O+M)	1.0	0.8	0.2	1	1.1	-0.1
IT Costs (Capital)	0.0	5.0	-5.0	0	1.7	-1.7
Business Resources	0.0	9.5	-9.5	0	6.3	-6.3
Total Costs	13.0	29.4	-16.4	13	22.4	-9.4

2006 Cost Variances to Budget ("BUD")

Accenture	$1.7M	An adjustment for CPI and change orders.
Gain Sharing	$0.4M	Negotiated settlement of Gain Sharing.
IT Costs (O+M)	($0.2M)	Partial year of O&M expenses.
IT Costs (Capital)	$2.8M	Incremental costs for field devices based on actual unit prices and numbers
	$2.2M	System performance improvements, enhancement support, and report development.
Business Resources	$9.5M	These costs are a continuation of the need for temporary staff in the Planning Department and Work Management Centre and increased costs required to deal with work order backlogs and longer processing times for a portion of 2006. Additional resources were required in the Work Management Centre to support the transition to the FFT system during roll out. As well, additional resources to drive system and process improvements that will reduce back office costs.

2007 Cost Variances to Budget ("BUD")

Accenture Fees	$0.8M	An adjustment for CPI and change orders.
Gain Sharing	$0.5M	Negotiated settlement of Gain Sharing.
IT Costs (O+M)	$0.1M	Increase in field devices being used.
IT Costs (Capital)	$0.4M	Mitigation of unacceptably low system performance.
	$1.3M	Enhancements to the EnVision technology to reduce the incremental back office costs.
Business Resources	$0.9M	Incremental back office staff required by the Work Management Centre to maintain to maintain the flow of work levels.
	$0.9M	Incremental back office staff required by the Planning Department to maintain to maintain the flow of work levels.
	$1.8M	Increased Contractor costs required to maintain the flow of work levels.
	$2.7M	Additional resources to drive system and process improvements that will reduce back office costs.

6. In Summary, EGD has demonstrated that EnVision has been, and continues to be, a prudent investment in business transformation.

GAS DISTRIBUTION ACCESS RULE

1. The purpose of this evidence is to seek approval of a revised transaction fee for the Invoice Vendor Adjustment ("IVA") functionality from 0.65% of the absolute value of the on-bill charge to 30 cents per transaction. The functionality is included as part of the Gas Distribution Access Rule ("GDAR" or "the Rule"). The Board had mandated that the Company provide for IVA functionality to gas vendors. The option allows gas vendors to bill single occurrence debits and credits to the Enbridge Bill for their Distributor Consolidated Billing ("DCB") customers.

2. In the Supplementary Settlement Proposal (Appendix E, N1-1-1, EB-2006-0034) the Board approved the Company's current IVA charge. In the settlement the parties agreed that:

    1. The IVA charge by the Company will equal 0.65% of the absolute dollar value of the adjustment. Parties agree that this IVA charge is an interim measure that will apply from June 1, 2007 to December 31, 2007, and is without prejudice to any Party proposing an alternative IVA charge commencing January 1, 2008.

    2. The Company will consult with interested parties and will consider the merits of bringing forward a different fee structure for a cost-based IVA charge. The Company will seek the approval of the OEB for the new IVA charge, to be effective January 1, 2008.

    3. Parties agree that the IVA charge is designed to only to recover the costs incurred by the Company to provide this service. As a result, Parties agree that there is no need to adjust the revenue deficiency as a result of forecast IVA charge revenues and costs. The Company will provide parties with a summary of 2007 IVA charge revenues and costs subsequent to December 31, 2007.

3. In late 2007 the Company consulted with interested parties to discuss the continuance of the IVA charge at the current level due to lack of cost history. The parties agreed with the continuance, with the understanding that the Company

would provide a summary of historical IVA charge revenues and costs in advance of any application to revise the charge. Please find attached a detailed summary of revenues and costs in Attachment 1. As evidenced in Attachment 1 the current approved charge of 0.65% has been insufficient to recover the Company's costs related to supporting the IVA service.

4. A number of factors were identified in order to derive the transaction fee for the IVA including: bad debt rate related to these transactions, impact on billing and collection call volumes and administrative costs to manage the vendor adjustment process and resolve any issues.

5. The fee includes the costs associated with one additional analyst to help support IVA activities whose responsibilities include: responding to questions, analyzing payments, performing financial reconciliations, and monitoring the bad debt experience.

6. Given the nature and potential dollar amounts of these transactions, it could be argued that IVA transactions have a higher risk of collection than normal utility receivables. However, in the absence of detailed collection data for the IVA transactions, the Company has assumed its 2008 Budget bad debt rate of 0.5% in the calculation of forecast costs.

7. In the last twelve month period, gas vendors posted nearly 250,000 IVA transactions, largely comprised of debit amounts of less than $2. In discussions with gas vendors who had submitted the largest numbers of these transactions it was communicated to the Company that a significant portion of these transactions would migrate to one of the new DCB rate ready billing line items. The new billing

line items will be introduced coincident with the implementation of the Company's CIS replacement project, expected to "go live" in the spring of 2009. Based on this information the Company has forecast a decline in the number of IVA transactions of more than 70%.

8. In a consultative meeting held with gas vendors on September 10, 2008, parties were presented with a proposal to amend the fee with two options. The first option proposed a revised percentage charged on the absolute dollar value of amounts submitted through the service and the second option was a flat fee per transaction. Gas vendors unanimously supported the flat fee per transaction proposal. Based on the forecast decline in transactions the company has calculated a fee of 30 cents per transaction to be effective January 1, 2009. Please refer to Attachment 1 for a detailed derivation of the Company's proposed fee.

Enbridge Gas Distribution
Summary of 12 mth IVA Activity Costs vs Fees Charged

Costs	Existing Activity costs & Fees		Impact on Costs/Fees W Change in Transctions	
1/4 of 1 FTE staff to monitor dollar levels,acctg etc	**16,750**		**16,750**	
Billing call code specific to IVAs	**6,000**		**6,000**	
Assumed Collection calls on 5 large IVAs	**35**		**35**	
Bad Debt on IVA charges (excludes Credits)	**1,718**	**24,503**	**1,357**	**24,142**
IVA Fees Charged to Vendors at .65% on absolute value $467,524		**3,038**		
	2008 Costs Under Recovered	**21,465**	**Costs To Recover**	**24,142**

Activity Levels	Actual Activity 12 mths # Trans	Dollars	Forecasted Activity 2009 # Trans	Dollars
Transaction Count Under $2/transaction	236,834	288,791	**236,834**	**288,791**
Other Debit Transactions	3,871	54,756	3,871	54,756
Other Credit Transactions	4,260	(123,977)	4,260	(123,977)
	244,965	219,570	244,965	219,570
Absolute Value of Dollars Billed as fee Basis		**$ 467,524**		
Assume a 2/3 reduction is low value transactions in 2009			-156,834	196,043
			88,131	271,482
Absolute Value of Dollars Billed as fee Basis				**$ 271,482**
Forecast Cost Recovery at .65%				**1,764.63**

Proposed Fee for 2009

Option #1	**Revised Percentage of Absolute Value**			
	Costs to recover		**$ 24,142**	
	Absolute Value over which costs must be recovered	$ 271,482		
	Fee Goes from .65% to 7% on absolute dollars			**8.9%**
	Costs recovered at 9.4% on Absolute Value		**$ 25,519**	
Option #2	**Revised Percentage of Absolute Value**			
	Costs to recover		**$ 24,142**	
	Forecast Number of Transactions to Recover Costs	88,131		
	Fee		**0.2739**	
	Costs recovered at $.27 per TRX		**$ 23,795**	

IN-FRANCHISE TITLE TRANSFER FEE

1. The purpose of this evidence is to seek approval of a new volume based fee for In-Franchise Title Transfers ("ITT"). Enbridge Gas Distribution Inc. (the "Company") proposes a fee of 2.5 cents per Gigajoule to be listed in Rider H "Balancing Service Rider". The fee would apply to the seller side of all ITTs effective April 1, 2009 to recover incremental costs associated with the continuance of the service after the implementation and "go live" date of the Company's Billing System Replacement Project.

2. The ITT functionality allows applicants (customers and gas vendors) who purchase their natural gas from someone other than the Company the ability to exchange gas between long and short delivered Banked Gas Account ("BGA") balances within the Company's franchise area. Currently, ITTs are provided as one of several methods to bundled and unbundled T-service customers to enact BGA load balancing adjustments in order to meet the tolerance levels described in the Handbook of Rates and Distribution Services ("Rate Handbook"). An ITT can be transacted between any of the Company's two points of acceptance.

3. The Company currently contracts for transportation services at two points of acceptance. One is a point in Western Canada which connects with the transmission pipeline of TransCanada Pipelines Limited. The second is a point of direct interconnection with the Company's gas distribution network in Ontario. Under the Company's current distribution rate structure the costs of long haul transportation or shipping costs are embedded into the delivery and load balancing charges of the end use customer. Customers delivering gas to the Ontario point of acceptance have shipped their own gas to the Company's franchise area and then

paid shipping costs again when the terminal location has consumed the gas and paid the Company's distribution charges. To keep Applicants whole, the Company had implemented a system of transportation service credits paid in accordance with Rider A "Transportation Service Rider". The transportation service credit serves to notionally move the point of all in-franchise gas exchanges back to the Western point of acceptance thereby eliminating the need for financial adjustment by the Company. As a result, customers may presently elect ITTs on a self-service basis through the EnTRAC system subject to certain conditions on a no charge basis.

4. As part of the approved 2005 Rate Case, RP-2003-0203 Settlement Proposal, dated June 17, 2004 (Exhibit N1, Tab 1, Schedule 1, pp. 45-46) the Company agreed that upon completion of the phase-in of fully allocated costs with respect to upstream transportation the Company would unbundle the transportation charge from its delivery and load balancing charge and the need for the transportation service credit would be eliminated. The four year cost phase-in ended on October 1, 2007 with distribution rates fully reflecting the Company's weighted average cost of transportation. However, the Company had requested the Board delay the unbundling of upstream transportation costs in order to save the substantial costs of modifying the legacy billing system as it was to be replaced, to which the Board agreed.

5. The Company is now in the process of completing the Billing System Replacement Project (expected in April 2009) and is therefore required to unbundle long haul transportation costs from delivery charges and list the charge as a separate line item on customers bill where required at that time. For customers delivering natural gas to the Ontario point of acceptance, the transportation service credit

payment will no longer be required and an end use-customer taking this service would not be invoiced upstream transportation on their customer bill. For Western point of acceptance customers the upstream transportation charge would be shown on the customer's bill as a separate line item.

6. This creates an inequity for title transfers between Customers with different points of acceptance. For example a Western T-service customer transferring gas to an Ontario T-service customer will not have paid for shipping and the Company has no current means to recover these costs via the receiving customer's invoice. Therefore, to maintain the ITT service offer the Company would be required to modify its processes and create a new credit and collection system to reconcile and settle these financial amounts between customers and the Company.

7. In the spring of 2008 the Company consulted with interested parties to discuss the continuance of the ITT service between pools with dissimilar points of acceptance. The Company proposed that the service could be modified to allow transfers only between similar points of acceptance, or that the service could be modified to continue as present with the Company managing a newly created credit and collection process. Interested parties agreed that the exchanges between dissimilar pools was a valuable load balancing service and should continue. The Company agreed to seek approval for this new service fee from the Board and to file in evidence a summary of forecasted costs and activity, with the understanding that the service fee was to be based on incremental cost recovery only.

8. A number of factors were identified in order to derive the ITT fee including: bad debt rate related to collecting toll charges, costs of remitting toll charges, impact on billing and collection call volumes, and administrative costs to manage the ITT

adjustment process and resolve any issues. The fee includes the costs associated with one quarter time associated to one analyst in the EnTRAC Financials group and with one quarter time associated to one analyst in Contract Compliance to help support ITT activities. Responsibilities include: responding to questions, analyzing ITT transactions, performing financial reconciliations, posting debits and credits in the remittance process, or through posting charges on customers bills and monitoring the bad debt experience. The Company has assumed the bad debt rate of 0.5% in the calculation of forecast costs.

9. In the past two years, Applicants have posted an annual average 1,500 ITT transactions with a total volume of 4,000,000 Gjs. Approximately, 35 % of these ITT transactions were between customers with a different point of acceptance. The Company proposes to recover the incremental costs relating to the support of the ITT service by applying a volumetric charge of 2.5 cents per Gigajoule on all transfers regardless of the plan types of the customer. Attached is a summary of forecasted costs and activity levels supporting the proposed fee.

Enbridge Gas Distribution

Summary of ITT Transaction History with Estimated Incremental Costs post CIS

Forecasted Costs to Handle ITT Transactions	**Estimated Activity Costs & Fees**
25% of 1 FTE staff to monitor dollar levels,accounting transactions on payments or charges,etc	$ **16,750**
25% of 1 FTE staff to monitor TT compliance transactions, BGA reconciliations	$ **16,750**
Bad Debt Exposure for Collections (.5% of receivable transaction dollars $991,515 -see below)	$ **49,576**
$40/hr for Service provider to add 280 amounts owing to EGD to customer bills	$ **11,200**
CSR support for bill enquiries: approx 25% of 250 will call seeking clarification $ 12/call	$ **840**
Total	$ **95,116**
Estimated fee/ gj (Estimate Costs $95,116/ ALL TT transactions 3,800,000 - see below)	$ **0.0250**

Forecasted Activity Levels	**12 Month Actual Activity**
Number of Transactions	1600
Average Annual ITT Transaction Volumes Total (GJ's)	3,800,000
Transfer Amount between dissimilar pools (GJ's) - 35% of ITTs have OTS/WTS toll adjustments	1,330,000
Receivable Amounts (Western to Ontario TT's) (50% x 1,300,000gj x 1.42/gj x 1.05 GST)	$ 991,515
Payable Amounts (Ontario to Western TT's) (50% x 1,300,000gj x 1.42/gj x 1.05 GST)	$ 991,515
Number of receivable transactions - where EGD is owed toll adjustment	280
Number of payable transactions - where vendor or customer is owed toll adjustment	280

Note: Assumes half of transactions are OTS to WTS and half are WTS to OTS

FIRM CAPACITY ON UPSTREAM TRANSPORTATION

1. This evidence addresses Enbridge Gas Distribution's ("EGD" or "the Company") proposal to revise its Rate Handbook to require direct purchase bundled service customers to demonstrate firm upstream transportation arrangements.

2. The proposed changes are intended to apply, in particular, to direct purchase bundled service customers who deliver their mean daily volumes to EGD's franchise area under their own upstream transportation arrangements (direct shippers). EGD relies on the firm delivery of these volumes in order to provide firm distribution service to the customer's terminal location, and to ensure supply demand balance and system reliability on its distribution system. EGD proposes to implement these changes effective November 1, 2009. Customers who are unable to demonstrate firm upstream transport would be denied direct shipper status and may be required to use EGD's upstream capacity to transport gas to the franchise area.

3. The proposed wording is shown at Exhibit C-1-4, Rate Handbook Part IV Terms and Conditions – Direct Purchase Arrangements, Section B - Obligation to Deliver and is reproduced below:

> Unless otherwise authorized by the Company in writing, each Applicant of a Direct Purchase Bundled Service must meet its obligation to deliver gas to the Company on any given day by Firm Transportation. The Applicant must provide to the Company, at the time of execution of the Service Contract, sufficient proof of the Applicant's Firm Transportation arrangements.

4. The Company' position is that the addition of this clause is required to mitigate an operational and financial risk to its customers and shareholders. As explained below, the Company submits that the use of non firm upstream services to meet firm delivery obligations may provide cost savings to an individual shipper, while

imposing the risk of reduced system reliability on all customers. The Company's proposal is consistent with the tariff provisions of several North American jurisdictions. A survey of other jurisdictions is filed as part of Exhibit C-1-9.

Rationale

5. Apart from customers subscribing to unbundled distribution service, EGD's customers fall into three categories:
   1. System supply – EGD procures supply and transports gas supply under Firm Transportation ("FT") arrangements to the franchise area;
   2. Western Transportation – EGD receives customer owned gas supply at Empress, Alberta and transports the gas supply using its long haul FT capacity to the franchise area; and
   3. Ontario Transportation – EGD receives customer owned gas supply at its franchise interconnects with TransCanada's PipeLines ("TCPL") system. Some Ontario Transportation customers use an assignment of EGD held TCPL long haul FT capacity. Since 2003, most Ontario Transportation customers have chosen to turnback their assignments of TCPL capacity and replaced it with their own transport capacity (direct shippers).

6. Direct shipper volumes constitute approximately 45% of average daily natural gas deliveries to EGD's franchise area and up to 15% of peak day demand EGD relies on these volumes to meet its obligation to provide firm distribution service on a daily basis, including under design day conditions. In addition, EGD curtails its interruptible customers and uses their supplies to meet firm demand on design day and other high demand days.

7. TCPL's Index of Customers[1] lists firm transportation contract information such as shipper name, volume, term and receipt and delivery points by delivery area. The Company's analysis of the Index of Customers, effective November 1, 2007 shows that contracts to EGD franchise, net of the Company's contracts, are approximately 64,000 Gj/d. As of November 1, 2007, daily deliveries from direct shippers equaled 520,937 Gj/d. It therefore appears that approximately 457,000 Gj/d are delivered either through Interruptible Transport ("IT") arrangements or through diversions of gas on firm contracts to other delivery areas, presumably because such arrangements deliver cost savings to shippers over contracting firm to the delivery area. TCPL classifies IT and diversions as discretionary services with a lower priority of service. Under severe weather conditions and/or constrained system operating conditions, these services have a higher likelihood of being curtailed. TCPL does not maintain or build facilities to serve discretionary load. As reliance on these services grows over time, the likelihood of curtailment is also expected to grow.

8. The supply shortfall resulting from curtailment of non firm services by TCPL could have very serious consequences for EGD's distribution system and its obligation to serve. As noted above, direct shipper volumes constitute upwards of 40% of supply on an average day and up to15% under design day conditions. Absent production or storage in EGD's franchise area, and given that EGD already relies on curtailment of its interruptible customers under peak demand conditions, EGD's ability to procure incremental supply is likely to be constrained. If available, such supply would be very expensive. Alternatively, EGD may have to institute curtailment of firm large volume customers to protect its system. Under

[1]http://www.transcanada.com/Mainline/info_postings/cde_archive/index_of_customers_archive.html Informational Postings - Index of Customers, 2007_Nov_ CDE.xls. TransCanada.com

extreme circumstances, EGD's small volume customers may suffer a loss of distribution service.

9. While the probability of the above scenario may be low, the cost consequences would be very significant and borne largely by customers who did not cause the supply shortfall. In EGD's view the proposed provision is a minimum and necessary condition to reduce the risk of supply related service disruption to its firm customers.

Survey of other jurisdictions

10. To validate its position and explore best practices, the Company commissioned an independent study and report on Local Distribution Company ("LDC") requirements in Canada and the US for customers with direct purchase or similar type arrangements[2]. The report describes various transportation options available to customers in the US and Canada. Union Gas and Gaz Métro Inc. require their direct purchase customers to have firm transportation arrangements.

11. The survey is intended to link provisions relating to force majeure, curtailment provisions and upstream transport requirements. Appendix 1 of the consultant's report (Exhibit C-1-9) summarizes research on requirements for firm transportation for various LDCs. An analysis of the summary identifies that of the forty LDCs researched in Canada and the US, all but six LDCs had provisions that allowed for:

- a mandatory assignment of LDC held transport, or,
- demonstration of firm upstream transportation arrangements, or,
- firm standby service with the LDC, or
- curtailment if the customer failed to deliver

[2] Report for Enbridge Gas Distribution – Tariff Provisions for Transportation and other Miscellaneous Provisions. E. Overcast – Black and Veatch

The option of curtailing customers who fail to deliver is only possible where the direct shipper status is offered only to a few large volume customers. LDCs that do not require such provisions and offer direct shipper status to all customers, typically had access to natural gas production and/or storage supplies within their franchise area.

Witnesses: M. Giridhar
K. Irani

Report for Enbridge Gas Distribution

Tariff Provisions for Transportation and other Miscellaneous Provisions

At the request of Enbridge Gas Distribution (EGD) Black and Veatch prepared a review of various tariff provisions as follows:

1. Provisions related to Force Majeure
2. Provisions related to service curtailment under extreme supply or capacity limitations
3. Provisions related to firm transportation service including mandatory assignment of upstream firm transportation service.

The review consisted of obtaining tariffs for local distribution companies (LDCs) in both the United States and Canada. Tariffs from over 40 utility service areas were reviewed to determine the existence of the listed requirements. Appendix 1 contains the summary of each of the reviewed tariffs by LDC.

Description of LDC Services

To fully understand the issues related to various tariff provisions, it is necessary to understand the types of LDC gas service offerings where services have been unbundled. Traditionally, gas LDCs provided a fully bundled service. The LDC met its bundled service obligation by contracting for gas supply and delivery to the city gate from pipeline suppliers. The LDC owned and operated the delivery service facilities downstream of the city gate consisting of pipes, regulators, meters and other assets designed to provide safe and reliable service to customers under the most extreme weather conditions- the design day. The LDC purchased a bundled transportation and supply service at the city gate and flowed that supply to retail customers as bundled delivery and supply service. In the 1980s, opportunities arose for the LDC to purchase transportation separate from gas supply and to contract directly with producers for their own supply of natural gas. As LDCs had service available on an unbundled basis, larger retail customers pursued the same opportunity at the retail level. Retail unbundling, to the extent permitted by regulators, followed the unbundling of long-haul transportation providers. Initially, only the largest commercial and industrial customers received unbundled service and in most cases LDCs limited the service to interruptible customers and firm customers with alternate fuels. Unbundled service took a number of different forms as LDCs opened the market for transportation. From this beginning, unbundled service evolved to offer the right for more customers, including residential customers, to purchase gas for delivery by the utility. Today, most LDCs offer some form of unbundled service.

The extent of unbundling in Canada and the United States varies among jurisdictions and even among LDCs in a jurisdiction. Between the extremes of no unbundling to complete unbundling, a variety of arrangements exist. Within this report, four basic models seem to capture the elements of unbundled service without addressing the particular characteristics of different programs under these models. The four models are as follows:

1. LDC provides bundled commodity or retail sales service
2. LDC takes delivery of customer owned gas in the production area and delivers the gas to customer or a full transportation service from wellhead to burner tip
3. Customer arranges for commodity and transportation to LDC city gate for LDC transport to meter
4. Full unbundling of all service where LDC provides delivery service only, marketers provide commodity, storage and transportation to system based on daily LDC requirements.

Each of these models of unbundling may be used alone or in combination with one or more of the other models. For example, many LDCs provide both unbundled transportation such as permitting some or all customers to purchase gas commodity and arrange for delivery to the city gate and bundled commodity service for customers who elect utility default service.

Each of these services imposes unique requirements relative to the LDC and its customers including end-use customers, marketers and brokers. Under the bundled commodity sales service, the LDC has the responsibility to acquire sufficient transportation, storage and peaking service capacity to deliver gas commodity from the production area to the city gate to meet the design day requirements of its customers. In addition, the LDC purchases sufficient supply on an annual basis to meet the daily, monthly, seasonal and annual gas commodity supplies to serve customers and to mange the variability in system loads based on the design day demand and the annual heating load.

LDCs may take gas deliveries for customers in the production area and transport the gas from well-head to burner tip. In this case only the commodity service is unbundled. The LDC retains the responsibility to acquire sufficient transportation, storage and peaking service to meet design day demand. The LDC additionally must purchase sufficient gas supply to meet the load of the customers that continue to use system gas. In addition, the LDC must balance the receipt and delivery of the gas commodity, adjust for fuel and losses and manage the day to day differential between gas delivery to the burner tip and actual loads for those customers who receive transport service.

Where customers contract for both gas supply and transportation to the city gate, the role of the LDC changes based on the particular model chosen for transportation. The role of the LDC in matching supply and demand on the system remains the same since only the LDC has the necessary information to manage the hourly and daily loads of the system. In some cases, the LDC manages the system by requiring firm delivery to the city gate through either LDC capacity release or non-recallable FT from the market. In other cases, the LDC provides firm back-up service for transportation customers through the use of LDC FT. Finally, some utilities require customers whose gas does not reach the city gate to curtail their consumption. As a practical matter, the option of interrupting customers whose gas does not reach the city gate represents a reasonable option only to the extent that transportation service is for the largest customers on the system and the number of such customers is small.

The option of managing the system to maintain reliability under the unbundled model that permits residential and small general service customers to receive distribution service from the LDC requires an extensive set of provisions designed to protect the system. LDCs correctly recognize that only the LDC is in the position to assure adequate assets to serve the design day load. The assets required to serve the design day load include pipeline transport, storage and peaking facilities. Even in a fully unbundled market, it is the LDC that must make certain that the level of FT service to the city gate including capacity to deliver wellhead supply and off system storage volumes to the city gate plus any on system storage assets equals the expected design day demand plus reserves. This issue is complicated when marketers use their own FT since it is difficult to assure that the FT service will be available on a design day.

Marketers have the incentive to deliver gas to markets based on the highest price available without regard to the LDC obligation to serve customers. Thus, marketers, in the absence of adequate financial incentives, may find it desirable to use FT capacity to deliver gas to other higher priced markets. Under this circumstance, the LDC cannot satisfy the design day requirements. Where service is provided to smaller customers, there is no option to curtail service for failure to deliver and the LDC would be required to follow a curtailment plan to protect the system from an outage and the substantial cost consequences of such an outage.

Given the various service types, it is appropriate to explain the rationale for these different tariff provisions. The regulatory process creates both obligations and rights for the regulated utility. It is common for utilities to refer to the obligation to serve and the right to a reasonable return. Obligations for a utility are limited obligations based on specific tariff provisions. The tariff, consisting of Rules and Regulations, Terms of Service, Rate Schedules and Contracts, defines both obligations and rights necessary to operate the system and to recover the prudently incurred costs of that operation. In addition, the tariff conforms to the requirements of the regulatory framework created by statute and rulemaking. For example, an LDC may have a line extension policy that limits the amount of free main and service line for a customer and beyond the free allowance a customer contribution is required. Each tariff provision represents a method of managing the system to provide safe and reliable service at reasonable and equitable rates or respond to extreme conditions resulting from events beyond the control of the LDC. A “force majeure” provision limits the utilities liability for events beyond their control that impact service. A “curtailment plan” provision provides for an orderly process of managing the system when there is inadequate supply to meet customer load requirements. Finally, provisions such as “mandatory assignment of upstream firm transportation” assures the LDC that there are sufficient capacity resources to meet design day requirements.

Force Majeure

LDCs include a force majeure provision to limit liability with regard to service. Schedule 1 provides a copy of the Peoples Gas System’s provision. This is a typical example of the more comprehensive version of a force majeure provision. In the comprehensive version, rights of both the Company and its customers are subject to protection under force majeure. Most comprehensive versions exclude the payment of bills directly from any claim of force majeure. For some utilities, force majeure is a defined term in the definitions of terms. In those cases, LDCs typically use the term in a subsequent tariff provision. Schedule 2 from Piedmont Natural Gas illustrates the definition and application as a typical example. Finally, some LDCs accomplish the protection of force majeure without explicitly defining the term. In those cases, the tariff contains a provision designed to specifically limit liability. Schedule 3 from Indiana Gas Company provides an example of this option.

Most utilities include a force majeure provision in the tariff and the provision applies to all of the service provided by the utility whether it is sales or transportation. This approach treats all service under the same conditions related to delivery of gas to customers. The conditions that prompt force majeure declarations impact the reliability of the portion or all of the system where capacity or gas commodity is inadequate to provide supply to all customers. From the operating perspective, the ability to limit the impact to transportation customers who fail to deliver commodity depends entirely on the ability to identify the customers for whom gas supply did not reach the city gate. As discussed below, this is possible where only the largest customers are transport customers. Where residential and small general service customers transport gas as well, it is necessary that the LDC take other steps to assure that service reliability is maintained in order to protect the system.

A key component of an LDC service is the responsibility for assuring safe and reliable operation of the system. Retail marketers have no direct economic interest in maintaining the reliability of the system. The economics of marketers' provision of service to customers for most LDCs is assured not by their deliveries but by the utility that through system operations provides service for reliability. Marketers' economics is at most impacted by potential penalty provisions related to balancing services provided by the utility. Even extreme penalties do not prevent gas from being diverted to higher priced markets under peak conditions placing the LDC system in jeopardy. Further, marketers have no incentive to acquire all of the firm transportation, storage and peaking service required to meet design day requirements because they have no obligation to serve. This means that ultimately the LDC must acquire sufficient capacity to meet the design day requirements. Further, only the LDC has a complete picture of the design day requirements. For this reason, it is imperative that the LDC develop plans to minimize the potential for service interruption to only those potential force majeure events. Curtailment plans provide for a tool to respond to force majeure.

Curtailment Priorities

The development of a curtailment priority system provides a tool that allows the LDC to maintain its system under adverse gas supply situations. Curtailment priority provisions grew out of the gas supply shortages of the 1970s. These provisions were designed to protect the integrity of the system and to create an orderly priority for shutting off supply to customers based on a plan approved by regulators that served the public interest. During the 1970s, gas LDCs actually implemented these plans forcing customers such as industry and schools to close in order to continue serving residential and critical needs customers such as hospitals.

Nearly all LDCs have specific curtailment provisions as part of their tariff. As with force majeure, these provisions vary among LDCs. Schedule 4 presents the curtailment provision of Baltimore Gas and Electric (BG&E). The BG&E curtailment provision provides substantial detail in addressing both transportation and supply customers. The provisions related to critical use gas are spelled out as a defined term. In addition, the provision provides a comprehensive set of options for addressing various situations requiring curtailment. Schedule 5 provides the curtailment provision for Questar Gas. This provision illustrates an abbreviated version of the curtailment provisions and provides for the priority of service restoration as well. Finally, Schedule 6 provides an example of an abbreviated curtailment procedure for Piedmont Natural Gas. Some utilities have emergency response procedures that define how the utility will respond to adverse operating conditions simply as a matter of prudent operation and planning even if they do not have a specific curtailment plan included as a tariff provision.

Regardless of the form of the tariff provision, curtailment represents a required operating procedure designed to minimize the potential cost of a gas system outage. Gas utilities recognize that circumstances may require that service be curtailed and attempt to minimize the impacts on customers through the management of a curtailment process.

Requiring Upstream FT for Transportation Service

As discussed above, there are four basic models of unbundled service including LDC transportation service. From a tariff perspective, transportation service represents one tariff element that exhibits a broad range of service provisions and types of service. With respect to the issue of upstream FT requirements, utilities take a variety of positions along the spectrum of options related to FT service to the city gate. Some LDCs oppose FT capacity release on interstate pipelines for marketers to serve end-use customers requiring instead that marketers use IT service and that customers either have their service curtailed when supplies do not reach the city gate or to contract with the LDC for backup service using the FT contracts of the LDC. Some utilities require that marketers use released FT to provide firm service to the city gate to match firm distribution service to the end-user. Other LDCs actually allocated FT and other assets to marketers to serve firm customers to the city gate based on the customers load requirements. In between these extremes there are a number of different transportation arrangements.

From a utility operating perspective, requiring that firm service behind the city gate be coupled with FT to the city gate is a necessity for LDCs that offer unbundled service to all customers including residential and small commercial customers. The FT service might be released FT with recall rights where marketers fail to meet their delivery obligations or lose the customers for whom the FT service was released. The FT service may also be service that marketers obtain (assuming such service is available to the city gate) by contracting with pipeline suppliers or by purchasing firm FT service without recall rights from another party who does not require the capacity. The requirement for FT to the city gate appears to be the most common approach where transportation is available for all customers and the LDC city gates are located in pipeline constrained areas. There is no fundamental reason to permit a lower quality of service to the city gate than for distribution service. To do shifts the cost of reliability to customers who have maintained firm service to the city gate.

For LDCs that serve only larger transportation customers, the transport service is only as firm as the delivery to the LDC city gate unless the customer contracts for a firm back-up service. Where backup service is not offered, customers are subject to curtailment in the event gas does not make it to the city gate. This type of service tends to be more prevalent where the LDC is located in a producing area (local production) or at a point on the pipeline system that is relatively unconstrained. LDCs, as the entity responsible for service reliability use these different provisions to provide safe and reliable service under the unique service requirements of the LDC service areas. The following table provides a summary the different options based on market conditions.

Table 1

Summary of Common Unbundled Transportation Offerings

Type of Service	Mandatory FT	Backup Service	Curtailment	Delivery
Large Volume Transport	No	Offered	If gas does not arrive at city gate	Customer responsibility
Large Volume Transport	Yes	None-Balancing service	Force majeure	Customer responsibility
Small Volume Transport	No	Required	Force majeure	Customer and Company
Small Volume Transport	Yes	None-Balancing service	Force majeure	Company

Schedule 7 provides an example from XCEL Minnesota of firm delivery service requiring FT to the city gate but providing for curtailment if gas supply does not reach the city gate and also offers firm backup service for failures to deliver. XCEL provides firm delivery service only to large customers with transportation to smaller customers contingent on the availability of an alternate fuel other than natural gas. Customers have an obligation to stop using gas if their supply fails to reach the city gate unless they have contracted for the backup service. In this example, the customer directly bears the risk of failure to deliver. Given the size and sophistication of these customers, this type of tariff option provides some level of protection for system integrity. However, if small volume residential and commercial customers received transportation service, this type of provision would not provide an adequate basis for managing system reliability.

The options related to firm service include released FT, assigned FT, firm standby sales service and requirements that upstream service quality match delivery service quality either firm or interruptible. For each utility, the requirement to manage system reliability plays an explicit role in transportation service requirements. In addition to the various FT or interruptible provisions, some utilities have the right to take customer owned gas to serve customers with a higher curtailment priority. When the LDC takes transportation gas to serve higher priority customers the transport customer is compensated for the gas based on a tariff provision that identifies the rate for purchasing such gas.

Schedule 8 from Bay State Gas provides an example of the assignment of FT service to customers or marketers desiring firm deliveries to customer premises. In addition, Schedule 8 provides details related to other assigned services and the process for assignment. This represents a detailed tariff provision covering a broad spectrum of the operating considerations. Some utilities assign a combination of FT, storage and peaking assets required to serve end-use customers. This is particularly the case when all customers have fully unbundled services available. The assignment of services other than pipeline service recognizes that to meet design day requirements of all system customers requires the use of more than pipeline assets because many LDCs do not have enough pipeline capacity to the city gate to meet the design day. Instead, LDCs use a combination of market area storage, production area storage and FT to the city gate and peaking supplies to meet the design day. The process of assignment varies based on different tariff provisions that provide for annual assignment or monthly assignment. Some LDCs do not assign capacity but offer released FT as an option for the marketer to obtain firm service to the city gate. Thus marketers have the option of providing their own FT but also have the option of purchasing the service from the utility.

For LDCs that offer transportation service without specific requirements related to FT, typically the LDC has a limited number of customers and transportation is offered as a companion rate to a sales rate in the event that gas is not delivered to the customer. Some LDCs do not provide transportation at all. As a practical matter, it is unreasonable to compare provisions where the number of transportation customers is limited to only the largest commercial and industrial customers to a system where any customer is eligible for transportation service and customers from all classes elect to receive transportation.

The ability to provide safe and reliable transportation service to all classes of customers and to plan for adequate firm design day assets- firm transportation to the city gate, storage and peaking service- requires that the LDC manage and acquire the capacity to meet design day. No other party has direct interest in managing asset acquisition for the whole system and no other party has the aggregate data necessary to assure reliable service. This suggests that for a competitive retail market to operate efficiently and economically, the LDC must acquire capacity assets and either assign those assets to retail customers for their use or provide mandatory standby service to shippers who do not have firm transport to the city gate to match the firm delivery obligations of their retail customers. Under the first option, once assets are assigned to customers, any marketer serving the customer would be allowed to use those assets to serve load and when the assets are not in use to serve load; to use those assets in other markets; or to use those assets for other services so long as that use is subordinate to the firm delivery obligation to retail customers who have contracted with the marketer for service using those assets. Absent mandatory assignment, LDCs must acquire sufficient assets to provide a mandatory firm standby service to assure design day reliability. This option would require that retail marketers either have firm service to the city gate to match the delivery obligations of their customers or contract with the LDC for mandatory standby service equal to the difference between the capability of the marketer to deliver firm city gate service and the delivery obligation of their customers.

Utility	Force Majeure or equivalent	Curtailment	Upstream FT	
Atlanta Gas	Applicable to all service	Yes	Required-Released FT, storage and peaking	
Atmos (LA)	None	No	No transport provided	
Bay State Gas	Applicable to all service	Yes	Required-Released FT, storage and peaking	
Atmos (CO)	Applicable to all service	Yes	None required-Service curtailed if gas is not delivered	
Atmos (IL)	None	Yes	None, firm standby service available	
Atmos (IA)	In Contracts applicable to commercial and transportation services		Service is interruptible unless customers contract for firm service through released capacity	
Atmos (KA)	Applicable to all service	Yes	Service is interruptible if gas is not delivered to city gate, gas may be taken to serve higher priority loads	
Atmos (GA)	Applicable to all customers	Yes	None required	
Atmos(midTX)	None	Yes	No transportation	
Atmos (TN)	Applicable to all customers	Yes	None required	
Atmos (MO)	Applicable to all customers	Yes	Interruption for failure to deliver and FT capacity release	

Atmos (KY)	Applicable to all customers	Yes	Subject to interruption	
Atmos (VA)	Applicable to all customers	Yes	Released FT and or firm standby service available, otherwise subject to curtailment	
BG&E	Applicable to all customers	Yes	Released FT	
Columbia (KY)	Applicable to all customers	Yes	Assigned FT	
Cascade (OR)	Applicable to all customers	Yes	FT provided under frozen provision, delivery service is non-firm and subject to curtailment	
Cascade (WA)	Applicable to all customers	Yes	Service is non-firm unless customer purchases separate firm backup service	
Con Ed	Applicable to all customers	Yes	FT required for firm delivery service	
Consumers (MI)	Applicable to all customers	Yes	Supplier retains pipeline capacity to serve its customers	
Connecticut Natural Gas	Applicable to all customers	Yes	Requires FT or firm standby service	
Connectiv Energy Delivery (DE)	Applicable to all customers	Yes	Firm standby service is available within contractual limits	
Duke Energy (OH)	Applicable to all customers	Yes	FT required for firm service, released capacity	

			available under conditions	
Equitable Gas (WV)	Applicable to all customers	Yes	Standby sales service available	
Vectren (IN)	Applicable to all customers	Yes	Interruptible interim supply service, transportation subject to curtailment	
NJ Natural Gas	Applicable to all customers	Yes	FT required to city gate, capacity release available	
Peoples Gas (FL)	Applicable to all customers		Service subject to curtailment if system reliability is threatened by failure to deliver	
Questar (UT)	Applicable to all customers	Yes	FT required to city gate, service is interruptible if no deliveries to city gate	
Piedmont Natural Gas (NC)	Applicable to all customers	Yes	Standby service available, otherwise subject to curtailment	
Southwest Gas (NV)	Applicable to all customers	Yes	Subject to curtailment if gas is not delivered for the customer	
Southwest Gas (AZ)	Applicable to all customers	Yes	Comparable service requirement from upstream provider and subject to curtailment for failure to	

			deliver, Capacity release service available	
Washington Gas Light (DC)	Applicable to all customers	Yes	Ft required either released capacity or separate capacity of supplier	
XCEL Energy (MN)	Applicable to all customers	Yes	Contract requires FT for firm delivery, Standby service agreement available, otherwise subject to curtailment	
PNM Gas (NM)		Yes	Subject to curtailment, standby service available	
Oklahoma Natural Gas	Applicable to all customers	Yes	Delivery subject to receipt of gas otherwise curtailed	
Empire District Gas Company (MO)	Applicable to transport customers	Yes	FT Required for firm service	
GazMetro	Applicable to all customers	None	FT required, capacity assignment available	
ATCO	Applicable to all customers	Yes	Not specified, subject to curtailment	
Terasen Gas-Whittier	Applicable to all customers	Yes	No transport	
Terasen Gas-Fort Nelson	Applicable to all customers	Yes	FT required	

VII

FORCE MAJEURE

In the event of either Company or Customer being rendered unable wholly or in part by force majeure to carry out its obligations under an application, acceptance of which has been made, or under a Rate Schedule or Service Agreement, other than the obligation to make payment, it is agreed that on such party giving notice and full particulars of such force majeure in writing to the other party as soon as possible after the occurrence of the cause relied on, then the obligations of the party giving such notice (other than the obligation to make payments), so far as they are affected by such force majeure, shall be suspended during the continuance of any inability so caused but for no longer period, and such cause shall as far as possible be remedied with all reasonable dispatch. It is further agreed that except for the obligation to make payments neither Company nor Customer shall be liable to the other for any damage occasioned by force majeure.

The term "force majeure" as employed herein shall mean acts of God, strikes, lockouts, or other industrial disturbance, acts of the public enemy, wars, blockades, insurrections, riots, epidemics, landslides, lightning, earthquakes, fires, storms, floods, washouts, arrests and restraints of the governments and people, civil disturbances, explosions, breakage or accidents to machinery or lines of pipe, the necessity for making repairs or alterations to machinery or lines of pipe, freezing of wells or lines to pipe, partial or entire failure of source of supply, planned or unplanned outages on the Company=s system or on any pipeline system, or the inability of any such system to deliver Gas, acts of civil or military authority (including, but not limited to, courts or administrative or regulatory agencies), and any other cause, whether of the kind herein enumerated or otherwise, and whether caused or occasioned by or happening on account of the act or omission of Company or Customer or any other person or concern, not reasonably within the control of the party claiming suspension and which by the exercise of due diligence such party is unable to prevent or overcome; such term shall likewise include (a) in those instances where either party is required to obtain servitudes, rights-of-way grants, permits or licenses to enable such party to fulfill its obligations hereunder, the inability of such party to acquire, or the delays on the part of such party in acquiring, at reasonable cost and after the exercise of reasonable diligence, such servitudes, rights-of-way grants, permits or licenses; and (b) in those instances where either party is required to furnish materials and supplies for the purpose of constructing or maintaining facilities or is required to secure grants or permissions from any governmental agency to enable such party to fulfill its obligations hereunder, the inability of such party to acquire, or the delays on the part of such party in acquiring, at reasonable cost and after the exercise of reasonable diligence, such materials and supplies, permits and permissions.

It is understood and agreed that the settlement of strikes or lockouts shall be entirely within the discretion of the party having the difficulty, and that the above requirement that any force majeure shall be remedied with all reasonable dispatch shall not require the settlement of strikes or lockouts by acceding to the demands of opposing party when such course is inadvisable in the discretion of the party having the difficulty.

Customer shall not be entitled to recover from Company any consequential, indirect, incidental or special damages, such as loss of use of any property or equipment, loss of profits or income, loss of production, rental expenses for replacement property or equipment, diminution in value of real property, or expenses to restore operations.

PIEDMONT NATURAL GAS COMPANY
SOUTH CAROLINA SERVICE REGULATIONS

Definition:
(e) “Force Majeure" shall mean acts of God, extreme weather conditions, strikes, lockouts, or other industrial disturbances, acts of the public enemy, war, blockades, insurrections, riots, epidemics, landslides, lightning, earthquakes, fires, hurricanes, tornadoes, storms, floods, washouts, arrests and restraints of governments and people, civil disturbances, explosions, breakages or accidents to machinery, lines of pipe or the Company's peak shaving plants, freezing of wells or lines of pipe, partial or complete curtailment of deliveries to the Company by its suppliers, reduction in gas pressure by its suppliers, inability to obtain rights-of-way or permits or materials, equipment or supplies for use in the Company's peak shaving plants, and any other causes, whether of the kind herein enumerated or otherwise, not within the control of the Company and which by the exercise off due diligence the Company is unable to prevent or overcome. It is understood and agreed that the settlement of strikes or lockouts shall be entirely within the discretion of the Company, and the above requirement that any force majeure shall be remedied with all reasonable dispatch shall not require the settlement of strikes or lockouts when such course is inadvisable in the discretion of the Company.

Application:
21. Curtailment or Interruption of Service. In the event of a curtailment or interruption of service, the Company shall use all reasonable diligence to remove the cause or causes thereof, but the Company shall not be liable for any loss or damage resulting from such curtailment or interruption due to accidents, force majeure, extreme weather conditions, operating conditions or causes beyond its control.

Schedule 3

Indiana Gas Company, Inc. D/B/A Sheet No. 59
Vectren Energy Delivery of Indiana, Inc. (Vectren North) Original Page 1 of 1
Tariff for Gas Service
I.U.R.C. No. G-19
Effective: February 14, 2008

GENERAL TERMS AND CONDITIONS APPLICABLE TO GAS SERVICE

21. LIMITATIONS OF LIABILITY
A. Neither Company nor Customer shall be liable to the other for any act, omission or event caused by strikes, acts of God, or unavoidable accidents or contingencies beyond its control.

B. Company shall not be liable for damages for any failure to supply gas or for an interruption, limitation, or Curtailment of Gas Service, whether or not such disruption is ordered by a governmental agency having jurisdiction, if such failure, interruption, limitation, or Curtailment is due to the inability of Company to obtain sufficient gas supplies at economical prices from its usual and regular sources or due to any other cause whatsoever other than willful default of Company.

C. Company shall not be liable for damages caused by defective piping or appliances on Customer's Premises.

D. Company shall not be liable for damages resulting to Customer or to third persons from the presence or use of gas or the presence of Company's equipment on Customer's Premises, unless due to the willful default or negligence on the part of Company.

Appendix A
Natural Gas Curtailment Plan

Section 2.3 of the Terms and Conditions of BGE's Gas Service Tariff specifies that in the event of a curtailment of gas supply, the Company will implement limitations to service in accordance with this Natural Gas Curtailment Plan. In addition to any orders of Federal or State authorities establishing priorities of or limitations to service, if the Company is unable to maintain safe minimum delivery pressure on part or all of its distribution system, this Curtailment Plans will be implemented. The Plan specifies the hierarchy of gas service and use during extraordinary situations and is consistent with Public Service Commission regulations, Maryland Emergency Management Agency requirements, BGE's Gas Emergency Manual Standards and the Maryland Natural Gas Supply Contingency Plan.

A. **Curtailment Hierarchy:** If curtailment of supply becomes necessary, and sufficient implementation time is available, customers will be notified that their use will be curtailed under the guidelines listed below. This curtailment hierarchy commences after customers receiving service under Rate Schedules IS and AIS are interrupted for distribution system purposes, and does not reflect a rigid sequence of operations, but rather a flexible option of alternatives necessary to react quickly and effectively to various circumstances. These steps may be implemented either sequentially or simultaneously, depending on the nature and extent of the emergency. Where immediate action is required to protect distribution system reliability and sufficient time is not available to implement the Curtailment Hierarchy detailed below, gas supply to specific areas of the distribution system may be temporarily discontinued, resulting in complete curtailment of all customers within the area.

The Company may curtail or temporarily discontinue gas supply in the following order without incurring any liability for any subsequent loss or damage which the Customer may sustain by reason of such curtailment or discontinuance of gas supply.

1. Supply for customers served under Schedules IS and AIS and Special Contracts is discontinued, except for Critical Use. Any Critical Use gas used, but not delivered by the Customer into the Company's distribution system is billed at the higher of the Production Rate or 110% of the highest Transco Zone 6 (non-New York) price during the curtailment period. BGE will not supply gas above Critical Use levels. Any gas used in excess of Critical Use levels will be billed at the Curtailment Penalty Rate.

2. Where the curtailment is supply related, including interstate gas pipeline capacity limitations, supply for customers served under Schedule C Non-Standby is discontinued, except for Critical Use. Any Critical Use gas used, but not delivered by the Customer into the Company's distribution system is billed at the higher of the Production Rate or 110% of the highest Transco Zone 6 (non-New York) price during the curtailment period. BGE will not supply gas above Critical Use levels. Any gas used in excess of the higher of verified Transportation Gas delivered into the Company's distribution system or Critical Use levels will be billed at the Curtailment Penalty Rate. Under all other

situations, Schedule C Non-Standby Service customers are included with all other Schedule C customers under paragraph 4.

3. Critical Use supply for customers served under Schedules IS and AIS is discontinued. Any gas used will be billed at the Curtailment Penalty Rate.

4. Supply for Daily Metered customers served under Schedule C electing Non-Standby Service, is discontinued except for Critical Use. Any Critical Use gas used, but not delivered by the Customer in the Company's distribution system, is billed at the higher of the Production Rate or 110% of the highest Transco Zone 6 (non-New York) price during the curtailment period. Any gas used in excess of Critical Use levels will be billed at the Curtailment Penalty Rate.

5. Critical Use supply for Daily Metered customers served under Schedule C electing Non-Standby Service and supply for customers served under Schedule C not covered under paragraph 4 is discontinued. Any gas used will be billed at the Curtailment Penalty Rate.

6. Supply for customers served under Schedule D is discontinued.

B. **Critical Use:** Critical Use is gas required for pilot use or to protect life, health, and public safety, or where a gas outage of up to 24 hours would cause irreparable damage to the environment and/or the Customer's property. Limits on the amount of Critical Use gas are specified in the individual Rate Schedules.

C. **Production Rate:** $1.20 per therm ($12 per Dth) which is the incremental cost of producing peak shaving gas.

D. **Curtailment Penalty Rate:** Failure by a Customer to comply with curtailment notices shall result in a penalty of $100 per Dth applied to all use of curtailed gas.

E. **Payment for Transportation Gas:** For curtailed customers, any customer owned transportation gas arriving at BGE's City Gate during the curtailment period but not delivered to the Customer will be purchased by the Company at the higher of the Production Rate or the Transcontinental Gas Pipeline Company (Transco) Zone 6 (non- New York) average daily price during the curtailment period.

F. **Sudden Failure of Alternate Fuel System:** Customers who experience a sudden failure of their alternate fuel system, upon obtaining permission and if conditions permit, will be allowed sufficient gas to permit an orderly shut-down or a quick repair. If permission is granted, gas used will be treated as Critical Use gas for up to 6 hours. When permission is denied, gas used will be charged to the customer at the Curtailment Penalty Rate.

G. **Report to the Commission:** Where a curtailment of natural gas supply is required under this Plan, a report will be submitted to the Public Service Commission within 30 days following the restoration of service explaining the causes of the curtailment. In the event that the curtailment extends beyond 3 months, interim reports will be submitted on a quarterly basis.

7.03 EMERGENCY SERVICE RESTRICTIONS

Emergency sales restrictions or interruptions may be necessary in the event of a major disaster or pipeline break. Such restrictions will generally be of short duration. Should the emergency be isolated to a portion of the Company's system, the restrictions will apply primarily to that area.

PRIORITY FOR TERMINATION OF SERVICE

To the extent practicable and prudent, restrictions will be made in the following order:

Termination Priority	Customers	Restriction
1st	Interruptible Service	All use
2nd	Firm commercial and industrial service using more than 130 Dth per day	All use
3rd	Firm commercial and industrial service using between 45 and 130 Dth per day.	All use
4th	Residential and all remaining commercial and industrial service	Isolation by area as required

PRIORITY FOR RESTORATION OF SERVICE

To the extent practicable and prudent, restoration of service will be made in the following order:

Restoration Priority	Customers
1st	Hospitals and other immediate social needs
2nd	Residential service
3rd	Firm commercial and industrial service using less than 45 Dth per day
4th	Firm commercial and industrial service using between 45 and 130 Dth per day
5th	Firm commercial and industrial service using more than 130 Dth per day
6th	Interruptible Service

Schedule 6

Piedmont Natural Gas
North Carolina

31. **Curtailment of Service**. It is contemplated that the Company will from time to time find it necessary to curtail or interrupt Gas Service to those Customers who purchase Gas from the Company under interruptible Rate Schedules. In addition, unavailability of Gas supplies, requirements of public safety or other factors beyond the control of the Company may make Curtailment or interruption of any Customer necessary. In all such events, to the extent practicable, the Company will curtail those Customers paying the least margin per Dekatherm first.

XCEL- Minnesota Provisions

2.0 **LIMITATION ON OBLIGATION TO DELIVER.** This Transportation Agreement is expressly contingent upon Customer or Agent's procurement of firm natural gas supplies and firm transportation to the Company town border station at ________________. If Customer fails to deliver gas to Company, Customer shall immediately cease using gas. Company is not obligated to provide backup sales service to Customer if Customer's gas supply is interrupted. Company may, at its option, agree to provide backup sales service under Paragraphs 6.0 and 6.1 of this Agreement only pursuant to a separate Standby Service Agreement.

6.0 **GAS SUPPLY RESERVATION CHARGE.** Customer may agree to pay a firm gas supply Reservation Charge pursuant to Paragraph 3.4 in order to reserve the right to supplemental or replacement firm sales service under the Standby Service Agreement between Company and Customer. The rights and obligations of Company and Customer regarding this backup service shall be as described in the Standby Service Agreement.

6.1 When gas service is provided under 6.0, Customer shall continue to pay the customer charge under the Firm Transportation Service rate schedule, rather than the customer charge in the firm sales service rate. On any day when Xcel Energy provides supplemental rather than replacement firm sales service, Customer's gas shall be considered the first through Customer's meter for billing purposes. In other respects, the Standby Service Agreement, rate and rules and regulations shall apply to all replacement or supplemental sales volumes.

DISTRIBUTION AND DEFAULT SERVICE
TERMS AND CONDITIONS

13.0 CAPACITY ASSIGNMENT

13.1 Applicability

Section 13.0 of these Terms and Conditions applies to all Suppliers providing Supplier Service to a Customer or Customers taking Daily-Metered or Non-Daily Metered Distribution Service from the Company pursuant to Section 11.0 or 12.0, respectively, of these Terms and Conditions. Section 13.0 shall also apply, to the extent noted herein, to any Customer acting as its own Supplier and taking Daily-Metered or Non-Daily Metered Distribution Service from the Company. The Company will assign and the Supplier shall accept each Customer's pro-rata shares of Capacity, if any, as established in accordance with this Section.

13.2 Identification of Capacity for Assignment

13.2.1 On or before September 1 of each year, the Company shall post on its Website or other such means the Capacity to be made available for assignment to Suppliers on each of twelve Assignment Dates beginning the following October. Such posting shall list, by Gas Service Area, all resource contracts eligible for assignment, the Capacity resource-allocation percentage by load factor, and the associated Capacity cost by load factor. Such posting shall also provide notice of any potential or pending contract change, including known and disclosable contract terminations, that are scheduled to require action by the Company between September 1 of the current year and October 31 of the next year. For capacity assignments occurring November 1, 2000, resource-allocation percentages and resource-allocation costs will be posted by the Company no later than October 22, 2000.

13.2.2 The Company shall post on its Website or other such means notice to Suppliers of any unscheduled contract changes that would affect the Capacity resource-allocation percentage or the associated Capacity cost. The Company will affirmatively notify all Suppliers serving Customers in the Company's system via electronic mail, facsimile or telephone, that such change has been posted. Such posting shall identify the contract under renegotiation and describe the nature of the renegotiation to the extent permitted by applicable confidentiality agreements. Such notice shall also provide an opportunity for Suppliers to comment on the contract under renegotiation. The Company shall further notify Suppliers of the results of such renegotiation no less than 60 days prior to the effective date of the contract change.

DISTRIBUTION AND DEFAULT SERVICE TERMS AND CONDITIONS

13.2.3 Capacity assigned by the Company may include Company-Managed Supplies that effectuate, at maximum tariff rates or lesser rate paid by the Company, the assignment of certain capacity contracts, including Canadian, Section 7(c) and other contracts that are not assignable to third parties.

13.3 Determination of Pro-Rata Shares of Capacity

13.3.1 The Company shall establish a Total Capacity Quantity ("TCQ") for each Customer taking Distribution Service. The TCQ represents the total amount of Capacity assignable to a Supplier on behalf of a Customer.

13.3.2 For a Customer receiving Default Service on or after November 1, 2000, the TCQ shall be the Customer's estimated Gas Usage on the Peak Day as determined by the Company each October prior to the Customer's enrollment into Supplier Service. The Company shall derive such estimate using a Daily Baseload and a Heating Factor based upon the Customer's historic Gas Usage during the Reference Period, or the best estimates available to the Company should actual Gas Usage information be partially or wholly unavailable.

13.3.3 For a Customer receiving only Distribution Service from the Company on February 1, 1999, or who had a written request filed with the Company on or before February 1, 1999 to receive only Distribution Service, the TCQ shall be zero except in cases where the Customer elects to have capacity assigned to its Supplier pursuant to Section 13.10, when the TCQ shall be less than or equal to the Customer's estimated Gas Usage on the Peak Day as determined by the Company. The Company shall derive such estimate using a Daily Baseload and a Heating Factor based upon the Customer's historic Gas Usage during a Reference Period ending in October 1999.

13.3.4 For a Customer that has converted from receiving Default Service to receiving only Distribution Service during the period beginning February 2, 1999 through and including March 31, 2000, the TCQ shall be zero until October 31, 2000, when the TCQ shall be changed to equal the Customer's estimated Gas Usage on the Peak Day as determined by the Company. The Company shall derive such estimate using a Daily Baseload and a Heating Factor based upon the Customer's historic Gas Usage during a Reference Period ending in October 1999. In the event that the Customer returns to Default Service prior to November 1, 2000, or if the Customer converts from daily-metered Distribution Service to non-daily-metered Distribution Service prior to November 1, 2000, the TCQ for the Customer shall be changed from zero to equal the Customer's estimated Gas Usage on the Peak Day as established above.

DISTRIBUTION AND DEFAULT SERVICE TERMS AND CONDITIONS

13.3.5 For a new Customer taking only Distribution Service as its initial service after February 1, 1999, the TCQ shall be zero except in cases where the Customer is a new Customer of record at a meter location where a former Customer of record received firm service from the Company any time during the preceding twenty-four (24) months, when the TCQ established by the Company for the former Customer shall become the TCQ for the new Customer. The Company will reduce said TCQ value for the new Customer upon a demonstration by the new Customer, or its designated representative, that a material and permanent difference between the former Customer's load profile and the new Customer's load profile warrants such a reduction. In the event that Default Service is provided at a new meter location for Gas Usage associated with new construction or an existing structure converting to natural gas service, the TCQ shall be zero, provided that the Customer initiates Supplier Service in accordance with Section 24.5 of these Terms and Conditions within 120 days of gas flow, or within 60 days of gas flow for Customers with annual volumes of 40,000 therms per year or more. Upon application by a new Customer, the LDC will provide that Customer with a description of the Customer's service options, a list of Suppliers authorized to provide service on its system and contact information for those Suppliers.

13.3.6 Once the Company establishes a TCQ for a Customer pursuant to this Section 13.3, it shall remain in effect for the purpose of determining the Customer's pro-rata shares of Capacity until such time that the Customer returns to Default Service. The Company shall establish a new TCQ value for the Customer pursuant to Section 13.3.2 if the Customer elects to take Supplier Service after returning to Default Service, unless otherwise established herein.

13.3.7 Notwithstanding the provisions of Section 13.3.6, where a Customer's TCQ is established on the basis of less than 12-months historical data, the TCQ may be recalculated at the Customer's request, or by request of the Customer's designated representative, upon the collection of 12-months of usage data. In the event that the TCQ established on the basis of 12-months usage data differs significantly from the TCQ initially established, the Company shall adjust the Customer's TCQ to be consistent with the 12-months usage data. Upon request by the Customer, or the Customer's designated representative, the Company shall change a Customer's TCQ where an error has occurred in the calculation of the TCQ or where the Customer, or its designated representative, demonstrates that a material and permanent change in the Customer's load profile warrants such an adjustment in the Customer's TCQ.

DISTRIBUTION AND DEFAULT SERVICE TERMS AND CONDITIONS

13.3.8 The Company shall determine the pro-rata shares of Pipeline Capacity, Underground Storage Withdrawal Capacity and Peaking Capacity assignable to a Supplier on behalf of a Customer as the product of the Customer's TCQ times the applicable Capacity Allocators. The Capacity Allocators for each class of Customers billed under the Company's Schedule of Rates shall be set forth annually in Appendix A to these Terms and Conditions.

13.3.9 The Company shall determine the pro-rata share of Underground Storage Capacity assignable to a Supplier on behalf of a Customer consistent with the tariffs governing the associated Underground Storage Withdrawal Capacity.

13.3.10 The Company shall determine the pro-rata shares of Peaking Supply assignable to a Supplier in accordance with Section 16.0 of these Terms and Conditions.

13.4 <u>Capacity Assignments</u>

13.4.1 On each Assignment Date, the Company will assign to the Supplier the pro-rata shares of Capacity on behalf of each Customer as determined by the Company in accordance with Sections 13.2, 13.3 and 13.7.

(1) The total amount of Pipeline Capacity, Underground Storage Withdrawal Capacity and Peaking Capacity assigned to the Supplier on behalf of the Customers in an Aggregation Pool shall, subject to the provisions of Section 13.4.2, be equal to the cumulative sum of the pro-rata shares of Pipeline Capacity, Underground Storage Withdrawal Capacity and Peaking Capacity for all Customers enrolled in said Aggregation Pool as of five (5) Business Days prior to the Assignment Date.

(2) Whenever the Company assigns incremental Underground Storage Withdrawal Capacity to the Supplier, the Company shall also assign to that Supplier additional Underground Storage Capacity pursuant to Section 13.8.

(3) The Peaking Capacity assigned to the Supplier shall establish the MDPQ for the Aggregation Pool in the Supplier's Service Agreement. In the event that the Company increases a Supplier's MDPQ, the Company shall also assign to that Supplier additional Peaking Supply pursuant to Section 16.0.

13.4.2 Except for the assignment of the initial block of capacity, the Company shall execute capacity assignments in increments of 200 MMBtus. The Supplier shall accept an initial

DISTRIBUTION AND DEFAULT SERVICE TERMS AND CONDITIONS

increment of 500 MMBtus of Capacity on the first Assignment Date when the sum of the pro-rata shares of Capacity to be assigned to the Supplier pursuant to Section 13.4.1 is equal to or greater than 400 MMBtus. The Supplier shall accept additional increments of Capacity in blocks of 200 MMBtus on the following Assignment Dates commensurate with any cumulative increase in the sum of pro-rata shares of Capacity assignable to the Supplier that are equal to or greater than 150 MMBtus. Each increment of Capacity accepted by the Supplier shall comprise Pipeline Capacity, Underground Storage Withdrawal Capacity and Peaking Capacity in proportion to the cumulative increase of the pro-rata shares of assignable Capacity as established in accordance with Section 13.4.1.

13.4.3 The Supplier shall accept, on behalf of any Customer taking Daily-Metered Distribution Service pursuant to Section 11.0 of these Terms and Conditions, and not combined by the Supplier into an Aggregation Pool under Section 24.6, the assignment of Capacity in the amount equal to the Customer's TCQ, as established pursuant to Section 13.3. Daily-Metered Customers shall be eligible for assignment of Capacity pursuant to the provisions of Section 13.4.2 to the extent that such Customers are combined by a Supplier into an Aggregation Pool within a designated Gas Service Area. In the event that a Customer is acting as its own Supplier, the Company shall assign Capacity to the Customer in an amount equal to the Customer's TCQ, as established pursuant to Section 13.3. In no case, shall a Customer who is acting as its own Supplier be eligible for the assignment of Capacity pursuant to the provisions of Section 13.4.2.

13.5 <u>Release of Contracts</u>

13.5.1 With the exception of Company-Managed Supplies, capacity contracts shall be released by the Company to the Supplier, at the maximum tariff rate or lesser rate paid by the Company and including all surcharges, through pre-arranged capacity releases, pursuant to applicable laws and regulations and the terms of the governing tariffs. In lieu of such capacity release, the Supplier may authorize the Company to retain the capacity for management and cost mitigation under the Company's Capacity Mitigation Service pursuant to Section 13.11 of these Terms and Conditions.

13.5.2 Capacity contracts released to a Supplier on an Assignment Date shall be released for a term beginning on the first day of the Month following the Assignment Date through the termination date of the respective capacity contract being assigned.

13.5.3 The Company reserves the right to adjust releases of Underground Storage Withdrawal Capacity in the event that fifty percent (50%) or more of the total Underground Storage

DISTRIBUTION AND DEFAULT SERVICE TERMS AND CONDITIONS

Withdrawal Capacity serving a Gas Service Area has been assigned to Suppliers. Such adjustments may include, but not be limited to, the reassignment of certain Underground Storage Capacity and Underground Storage Withdrawal Capacity as Company-Managed Supplies in order for the Company to maintain operational control over capacity resources associated with system balancing, and/or the retention of specific capacity resources associated with system balancing and the implementation of a balancing charge to offset the associated costs.

In order to provide notice of the potential for such an adjustment, the Company will post information regarding its customer-migration statistics each September 1, including the percentage of Underground Storage Withdrawal Capacity assigned to Suppliers in accordance with this section. To the extent that the Company determines that such adjustment is necessary, based on the level of capacity assigned to Suppliers, the Company shall notify Suppliers of the terms of the proposed adjustment no later than 90 days prior to the implementation of such adjustment.

13.6 Annual Reassignment of Capacity

13.6.1 On each Annual Reassignment Date, the Company shall adjust the capacity assignments previously made to a Supplier to conform with the Company's resource and requirements plans. Such previously assigned Capacity shall be replaced by the assignment to the Supplier of the pro-rata shares of the same or similarly situated Capacity on behalf of the Customers enrolled in the Supplier's Aggregation Pools (as of the first day of the Month following the Annual Reassignment Date).

13.6.2 If the reassignment of Underground Storage Withdrawal Capacity requires adjustments to the Underground Storage Capacity previously assigned to a Supplier, the Company shall reassign Underground Storage Capacity to such Supplier, and the Company and the Supplier shall address any associated increments and decrements to inventories in place pursuant to Section 13.8 of these Terms and Conditions.

13.6.3 If the reassignment of Peaking Capacity is required by adjustments to the MDPQ for the Supplier's Aggregation Pool, the Company shall reassign Peaking Supply to such Supplier, and the Company and the Supplier shall address any associated increments and decrements to supplies pursuant to Section 16.0 of these Terms and Conditions.

DISTRIBUTION AND DEFAULT SERVICE TERMS AND CONDITIONS

13.7 Recall of Capacity

13.7.1 If the pro-rata shares of Capacity assignable to a Supplier declines because one or more of the Supplier's Customers has returned to Default Service, the Company shall have the right, but not the obligation, to recall from the Supplier the pro-rata shares of Capacity previously assigned to the Supplier on behalf of such Customers. The decision on whether to exercise its capacity-recall rights shall be made by the Company in its sole reasonable discretion subject to the conditions set forth in Section 13.7.2. If the Company elects to recall Capacity from a Supplier pursuant to this Section, such recall shall be made on the first Assignment Date following the effective date of the Customer's return to Default Service.

If the Company elects to recall Underground Storage Withdrawal Capacity from the Supplier pursuant to this Section, the Company shall reduce the Underground Storage Capacity associated with the affected Aggregation Pool in accordance with Section 13.8 of these Terms and Conditions. If the Company elects to reduce the MDPQ in the Supplier Service Agreement, the Company shall reduce the Peaking Supply associated with the affected Aggregation Pool in accordance with Section 16.0 of these Terms and Conditions.

13.7.2 The Company shall, in its sole reasonable discretion, determine whether to exercise its capacity-recall rights pursuant to Section 13.7.1, except in the following circumstances, where the Company shall recall capacity associated with Customers returning to Default Service at the time of the next Assignment Date in accordance with the provisions of Section 24.5 of these Terms and Conditions:

(1) The Supplier returning said Customers to the Company's Default Service certifies that it is ceasing all business operations in Massachusetts;

(2) The Supplier returning said Customers to the Company's Default Service certifies that it will no longer offer service to a particular market sector, i.e., residential, small commercial and industrial ("C&I"), medium C&I, and/or large C&I Customers, and therefore, once such Customers are returned to Default Service, the Supplier is not eligible to re-enroll Customers of that type for a minimum time period of one year;

(3) The Supplier demonstrates that it has provided Supplier Service to the Customer for at least 12 consecutive months and that the Capacity to be recalled by the Company has been held by the Supplier, on behalf of the Customer, for a period

DISTRIBUTION AND DEFAULT SERVICE
TERMS AND CONDITIONS

equal to the sum of one or more 12-month increments. Except that, the Company will recall capacity associated with a Customer who converted from Default Service to receiving only Distribution Service during the period between November 1, 1999 and March 31, 2000, and was assigned Capacity pursuant to sections 13.3 and 13.4 as of November 1, 2000.

(4) To the extent that the return of Customers to Default Service does not occur pursuant to the conditions set forth in Sections 13.7.2(1), (2) or (3), the Company's discretion to recall Capacity shall be exercised so as to preclude the inappropriate avoidance of Capacity-cost responsibility, while minimizing the potential for inhibiting the routine enrollment, switching and termination of Customers from Supplier Service to Default Service.

13.7.3 In the event that a Customer in a Supplier's Aggregation Pool switches to another Supplier, the Company shall recall from the former Supplier said Customer's pro-rata shares of Capacity for reassignment to the new Supplier pursuant to Section 13.4. There shall be no change in the Customer's TCQ used to determine the Customer's pro-rata shares of Capacity for reassignment to the new Supplier. The recall of such Capacity from the Customer's former Supplier and the assignment of Capacity to the new Supplier shall be made on the Assignment Date following the effective date of the Customer's switch in Suppliers.

If the Company recalls Underground Storage Withdrawal Capacity from the Customer's former Supplier, the Company shall reduce the Underground Storage Capacity associated with the affected Aggregation Pool in accordance with Section 13.8 of these Terms and Conditions. If the Company reduces the MDPQ in the Customer's former Supplier's Service Agreement, the Company shall also reduce the Peaking Supply associated with the affected Aggregation Pool in accordance with Section 16.0 of these Terms and Conditions.

13.7.4 The recall of Capacity by the Company shall entail the recall of released contracts pursuant to governing tariffs, and/or the reduction in assigned quantities set forth in the Supplier's Service Agreement. The recall of Capacity shall be executed in decrements of 200 MMBtus, commensurate with the cumulative reduction in the pro-rata shares of Capacity assignable to the Supplier that is equal to or greater than 150 MMBtus. Each decrement of Capacity assigned to the Supplier shall comprise Pipeline Capacity, Underground Storage Withdrawal Capacity and Peaking Capacity in proportion to the cumulative decrease in the pro-rata shares of Capacity recalled from the Supplier.

DISTRIBUTION AND DEFAULT SERVICE TERMS AND CONDITIONS

13.7.5 In the event that a Supplier is declared ineligible to nominate Gas for thirty (30) days pursuant to Sections 11.6.6 or 12.6.3 of these Terms and Conditions, the Company shall have the right to recall any or all Capacity assigned to said Supplier. If the Supplier is reinstated at the end of such 30-day period, the Company shall reassign Capacity to the Supplier on the next Assignment Date pursuant to Section 13.4. There shall be no change in the TCQ values used to determine the Supplier's Customers' pro-rata shares of Capacity for reassignment.

13.7.6 In the event that a Supplier is disqualified from service for a one (1) full year pursuant to Sections 11.6.6 or 12.6.3 of these Terms and Conditions, the Company shall recall any or all Capacity assigned to said Supplier. If the Supplier is reinstated at the end of such period, the Company shall reassign Capacity to the Supplier on the next Assignment Date pursuant to Sections 13.4 and 13.5.

13.7.7 In the event that the Supplier fails to meet the applicable registration and certification requirements established by law or regulation, fails to satisfy the requirements and practices as set forth in Section 24.3 of these Terms and Conditions, fails to be and remain an approved shipper on the upstream pipelines and underground storage facilities on which the Company will assign capacity, fails to make timely payment under the assigned contracts, or fails to comply with or perform any of the obligations on its part established in these Terms and Conditions or in the Supplier Service Agreement, the Company shall have the right to recall permanently any or all Capacity assigned to said Supplier. This section shall also apply to a Customer acting as its own Supplier.

13.7.8 The Supplier shall forfeit its rights to Capacity recalled by the Company pursuant to this section. Such forfeiture shall be affected in accordance with applicable laws and regulations and the governing tariffs. In the event of capacity forfeiture pursuant to this Section, the Supplier shall be responsible to compensate the Company for any payments due under the contracts prior to forfeiture, as well as any interest due thereon. The Company will not exercise discretion in the application of the forfeiture provisions of this Section. This section shall also apply to a Customer acting as its own Supplier.

13.8 <u>Underground Storage Capacity</u>

13.8.1 On each Assignment Date, the Company shall release Underground Storage Capacity to a Supplier that accepts the assignment of Underground Storage Withdrawal Capacity pursuant to Section 13.4. The Company shall assign such Underground Storage Capacity consistent with the tariffs governing the release of the associated Underground Storage Withdrawal Capacity.

DISTRIBUTION AND DEFAULT SERVICE TERMS AND CONDITIONS

13.8.2 If the Company assigns Underground Storage Capacity to a Supplier pursuant to Section 13.8.1 above, the Company shall transfer in-place gas inventories to the Supplier. For incremental assignments, the quantity of incremental inventories to be transferred from the Company to the Supplier shall be determined by multiplying the incremental Underground Storage Capacity assigned to the Supplier on the Assignment Date, times the applicable Storage Inventory Percentage described in Section 13.8.5. The Supplier shall be charged the Company's weighted average cost of inventories in off-system storage facilities for each Dekatherm transferred from the Company to the Supplier. The Company shall post the Company's weighted average cost of inventories, by Gas Service Area, on its Website by the 15th of the Month preceding the next Assignment Date.

13.8.3 In the event that the Company recalls Underground Storage Withdrawal Capacity from the Supplier pursuant to Section 13.7, the Company shall also recall Underground Storage Capacity from the Supplier. The Company shall determine the total Underground Storage Capacity to be recalled from the Supplier in accordance with the tariffs governing the Underground Storage Withdrawal Capacity returned to the Company.

13.8.4 If the Company recalls Underground Storage Capacity from a Supplier pursuant to Section 13.8.3, the Supplier shall transfer in-place gas inventories to the Company. The quantity of inventories to be transferred from the Supplier to the Company shall be determined by multiplying the decremental Underground Storage Capacity times the applicable Storage Inventory Percentage described in Section 13.8.5. The Supplier shall be reimbursed at the Company's weighted average cost of inventories in the off-system storage facilities serving the applicable Aggregation Pool as of the Assignment Date, for each Dekatherm transferred from the Supplier to the Company. The Company shall post the Company's weighted average cost of inventories, by Gas Service Area, on its Website by the 15th of the Month preceding the next Assignment Date.

13.8.5 Underground Storage Inventory Percentages shall be the ratio of the unassigned inventory levels in each storage resource that exists on the Assignment Date and the maximum Underground Storage Capacity of each storage resource less any Underground Storage Capacity previously assigned.

DISTRIBUTION AND DEFAULT SERVICE TERMS AND CONDITIONS

13. 9 Company-Managed Supplies

13. 9.1 The Company shall provide access to and ascribe cost responsibility for the pro-rata shares of certain capacity contracts, including Canadian, Section 7(c) and other contracts that are not assignable to third-parties.

13. 9.2 The Supplier's Service Agreement shall set forth the quantity of each Company-Managed Supply assigned to the Supplier pursuant to Sections 13.4 and 13.8.

13. 9.3 The Company shall notify the Supplier of the conditions and/or restrictions on the use of Company-Managed Supplies.

13. 9.4 The Company shall invoice the Supplier for its pro-rata shares of the demand charges for capacity contracts assigned to the Supplier as Company-Managed Supplies. The Company shall also flow through to the Supplier all costs incurred from the utilization of Company-Managed Supplies on behalf of the Supplier.

13.9.5 The Company shall nominate quantities to the Delivering Pipeline and/or other interstate pipelines and off-system storage operators on behalf of Suppliers to which the Company has assigned the Company-Managed Supply, provided that the requested nomination conforms to the tariffs governing the resource. The Supplier shall communicate its desired nomination quantities to the Company subject to the provisions in Sections 11.3 and 12.3 of these Terms and Conditions, unless earlier deadlines are required by the applicable contract terms.

13.10 Open-Season Capacity Assignments

A Customer that was either receiving only Distribution Service from the Company on February 1, 1999, or had a written request filed with the Company on or before February 1, 1999 to receive only Distribution Service, may elect for its Supplier to accept the assignment of its pro-rata shares of Capacity as determined by the Company in accordance with Section 13.3. The Customer must have submitted to the Company, on or before the last day of the designated Open Season, a completed application for capacity that is signed by both the Customer and Supplier. All assignments of Capacity made on behalf of such electing Customer shall be executed in accordance with Sections 13.0 and 16.0 of these Terms and Conditions.

**DISTRIBUTION AND DEFAULT SERVICE
TERMS AND CONDITIONS**

13.11 Capacity Mitigation Service

13.11.1 Capacity Mitigation Service is available to Suppliers that have been assigned capacity pursuant to Section 13.4 of these Terms and Conditions. Such Suppliers shall have the option to take Capacity Mitigation Service from the Company for contracts that would otherwise be released to the Supplier in accordance with Section 13.5 of these Terms and Conditions. Company-Managed Supplies and Peaking Capacity are excluded from the Capacity Mitigation Service.

13.11.2 Within five (5) Business Days prior to the Annual Reassignment Date, the Supplier must designate those contracts that would otherwise be released to the Supplier pursuant to Section 13.5, as contracts to be managed by the Company for cost mitigation in accordance with the Company's Capacity Mitigation Service. Such designation will be effective for the period November 1 through October 31. Such notice shall be communicated in accordance with the Supplier's Service Agreement.

13.11.3 The Supplier shall pay to the Company the maximum-tariff rate or lesser rate paid by the Company, including all surcharges, for the capacity contracts that are retained and managed by the Company. The Company shall bill the Supplier monthly for such charges.

13.11.4 The Company will market capacity contracts designated by Suppliers for mitigation through the Capacity Mitigation Service. The Supplier shall receive a credit on its bill for Capacity Mitigation Service equal to the pro-rata share of the proceeds earned from the marketing of such capacity contracts, less 15 percent, which will be retained by the Company in exchange for such contract management. Such credit shall be determined on a contract-specific basis at the end of each Month, and will be included in the bill sent to the Supplier in the following Month.