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Cost of Gas Adjustment Clause

Section

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6.01 Purpose

The purpose of this Cost of Gas Adjustment Clause ("CGAC") is to establish a procedure that allows Boston Gas Company d/b/a National Grid (the "Company"), subject to the jurisdiction of the Department of Public Utilities (the "Department"), to uniformly adjust, on a semiannual basis, its rates for firm gas sales in order to recover costs of gas supplies, along with any taxes applicable to those supplies, pipeline capacity, the costs of local production and storage, gas acquisition expense, bad debt expense, and the costs of purchased gas working capital to reflect the seasonal variation in the cost of gas, and to credit to firm sales customers all supplier refunds, capacity credits from margins associated with capacity release, off system sales, and the release of downstream assets; and all commodity credits from interruptible sales, non-firm gas sales, and the assignment of Canadian gas supply contracts.

6.02 Applicability

This CGAC shall be applicable to all firm sales made by the Company unless otherwise designated. The application of the clause may, for good cause shown, be modified by the Department. See Section 6.12, "Other Rules."

6.03 Cost of Firm Gas Allowable for CGAC

All costs of firm gas including, but not limited to, commodity costs, taxes on commodity, demand charges, local production and storage costs, gas acquisition expense, bad debt expense, gas used in Company operations, transportation fees, costs associated with buyouts of existing contracts, and purchased gas working capital may be included in the CGAC. Any costs recovered through application of the CGAC shall be identified and explained fully in the semi-annual filing outlined in Section 6.11.

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6.04 Effective Date of Gas Adjustment Factor

The date on which the seasonal Gas Adjustment Factors ("GAF") become effective will be the first day of each season as designated by the Company. Unless otherwise notified by the Department, the Company shall submit GAF filings as outlined in Section 6.11 of this clause at least 45 days before they are to take effect. To the extent that the Company files an interim GAF filing in accordance with the provisions of Section 6.12, the GAF will become effective on the first day of the next month as designated by the Company.

6.05 Definitions

The following terms shall be defined in this section, unless the context requires otherwise.

(1) Bad Debt Expense is the uncollectible expense attributed to the Company's gas costs.

(2) Capacity Release Credit is the economic benefit derived from sales of upstream capacity that will be credited to firm sales customers. Ninety (90) percent of capacity release credits will be credited to firm sales customers.

(3) Combined Tax Rate is the combined state and federal income tax rate.

(4) Commodity Credits are the commodity cost of gas assigned to non-firm sales to which the GAF is not applied. Non-firm sales include sales made under interruptible contracts and non-firm contracts.

(5) Deliverability Percent is the percent of downstream production and storage service from Company-owned facilities (i.e., Liquefied Natural Gas ("LNG") and Liquefied Petroleum Gas ("LPG")) used for system deliverability as determined by the Department from time to time.

(6) Economic Benefit is the difference between the revenue and the marginal cost determined to service non-firm customers.

(7) Gas Acquisition Expenses include the costs incurred by the Company in its most recent test year to procure and transport gas supplies to the Company's city gate.

(8) Interruptible Sales Credit is the economic benefit derived from interruptible sales that will be credited to firm sales customers. Ninety (90) percent of interruptible sales credits will be credited to firm sales customers.

(9) Inventory Finance Charges are as billed in each Peak Season for annual charges. The total shall represent an accumulation of the projected charges as calculated using the monthly average of financed inventory at the existing (or anticipated) financing rate through a trust or other financing vehicle.

Cost of Gas Adjustment Clause

(10) Local Production and Storage Costs include the costs of providing storage service from Company-owned storage (i.e., LNG and LPG) as approved by the Department.

(11) Maximum Daily Contract Quantity (“MDCQ”) is determined annually for each season. The calculation uses billing histories for the previous peak and off-peak seasons. The number of therms used in each billing period will be the sum of the highest daily uses for each month.

(12) Number of Days Lag is the number of days lag to calculate the purchased gas working capital requirement.

(13) Off-Peak Commodity is, unless otherwise approved by the Department, the gas supplies procured by the Company to serve firm load in the Off-Peak Season.

(14) Off-Peak Demand is, unless otherwise approved by the Department, the storage and transmission capacity procured by the Company to serve firm load in the Off-Peak Season.

(15) Off-Peak Period Reconciliation Date for the Company will be coincident to the next off-peak period GAF filing, 45 days prior to the next off-peak period effective date.

(16) Off-Peak Season for the Company is the summer season of May 1 through October 31.

(17) Other Capacity Credits are the Economic Benefit derived from non-firm transactions to which the GAF is not applied, including non-firm contracts, off-system sales, and sales for resale. Ninety (90) percent of other capacity credits earned will be credited to firm sales customers.

(18) Peak Commodity is, unless otherwise approved by the Department, the gas supplies procured by the Company to serve firm load in the Peak Season.

(19) Peak Demand is, unless otherwise approved by the Department, the storage and transmission capacity procured by the Company to serve firm load in the Peak Season.

(20) Peak Period Reconciliation Date for the Company will be coincident to the next peak period GAF filing, 45 days prior to the next peak period effective date.

(21) Peak Season for the Company is the winter heating season of November 1 through April 30.

(22) Proportional Responsibility Allocator is the percentage allocator for peak period capacity charges as determined in the Company’s most recent base distribution rate case for total firm sales load.

(23) Purchased Gas Working Capital is the allowable working capital derived from peak and off-peak gas costs.

Cost of Gas Adjustment Clause

(24) Weighted Cost of Capital is the weighted cost of capital as set in the Company's most recent base distribution rate case.

(25) Weighted Cost of Debt is the weighted cost of debt as set in the Company's most recent base distribution rate case.

(26) Weighted Cost of Equity is the weighted cost of equity as set in the Company's most recent base distribution rate case.

6.06 Gas Adjustment Factor Formula:

Peak Formula:

The Peak GAF (excluding that applicable to General Service Rates G-44B and G-54B) shall be comprised of a peak demand factor, a peak commodity factor, a peak bad debt factor, a peak gas acquisition expense factor, and a peak working capital factor calculated at the beginning of the Peak Season according to the following formula:

$$GAFp = DFp + CFp + BDFp + GAEFp + WCFp$$

The Peak GAF's applicable to General Service Rates G-44B and G-54B shall be comprised of a peak demand factor to be applied to the customer's Maximum Daily Contract Quantity and a peak commodity factor, a peak bad debt factor, a peak gas acquisition expense factor, and a peak working capital factor to be applied to the customer's monthly consumption, calculated at the beginning of the Peak Season according to the following formulae:

$$GAF1 = DFpc$$
$$GAF2 = CFp + BDFp + GAEFp + WCFp$$

Pursuant to the Department's ruling in D.P.U. 20-120, the Company has the right to petition the Department for a one-time adjustment to its Local Production and Storage Costs during the period October 1, 2022 through October 1, 2025.

Peak Demand Factor (DFp) Formula:

$$DFp = \frac{Dp - CCp + RApd - RApcc}{P{:}Sales} - R1d - R2d$$

and:

$$Dp = Sum{:}PD + (PS \times PSP) + (Sum{:}AD \times PR)$$

and:

$$CCp = Sum{:}\ CM \times PR$$

Cost of Gas Adjustment Clause

and, if the Company proposes and the Department approves an adjustment to the Local Production and Storage Cost Allowance, then:

$PS_C = PS_{PY} + PSAdj$

with

PS_{PY} = Local Production and Storage Cost Allowance approved by the Department in the Company's most recent base distribution rate case

$PSAdj = (RB_{PS} \text{ x } PTRR) + DEPR_{PS} + O\&MAdj + PT_{PS}$

and

$O\&MAdj = O\&M_{PY} \text{ x } PBR\%$

Where:

Dp: Demand Charges allocated to the peak period as defined in Section 6.05.

CCp: Capacity Credits allocated to the peak period as defined in Section 6.05

RApd: Peak demand charge reconciliation adjustment - Account 175.20 balance, inclusive of the associated Account 175.20 interest, as outlined in section 6.08.

RApcc: Peak Capacity Credit Reconciliation Adjustment - Account 175.56 balance, inclusive of the associated Account 175.56 interest, as outlined in section 6.08.

P:Sales: Forecasted billed sales volumes associated with the peak period.

PD: Demand Charges billed to the Company for peak period capacity as defined in section 6.05.

AD: Demand Charges billed to the Company for year round capacity as defined in section 6.05.

PS: Local Production and Storage Costs as defined in section 6.05. Once approved by the Department, the Local Production and Storage Cost Allowance remains fixed until a change is approved by the Department.

PSP: Percent of Local Production and Storage costs not used for distribution system deliverability, as defined in section 6.05.

PR: Proportional Responsibility allocator as defined in section 6.05.

CM: Economic Benefit derived from non-core sales as defined in section 6.05.

R1d, R2d Per unit supplier refunds from pipeline demand charges. The per-unit supplier refunds associated with refund program credits derived from Account 242.1, "Undistributed Gas Suppliers' Refunds". See section 6.07.

Cost of Gas Adjustment Clause

CPS: Cumulative Production and Storage-related capital investment recorded as in-service since March 31, 2020, the date of end of the test year in the Company's most recent base distribution rate case.

RB_{PS}: Rate Base associated with the Cumulative Production and Storage-related capital investment (CPS) as of the end of the prior calendar year.

PTRR: The pre-tax rate of return shall be the after-tax weighted average cost of capital established by the Department in the Company's most recent base distribution rate case, adjusted to a pre-tax basis by using currently effective federal and state income tax rates applicable to the period of the eligible Production and Storage investment.

$DEPR_{PS}$: The annual depreciation expense associated with the Cumulative Production and Storage-related capital investment (CPS) as of the end of the prior calendar year.

O&M: The annual recovery of LNG-related O&M expenses included in the Local Production and Storage Cost Allowance as approved by the Department.

O&MAdj: The adjustment for LNG-related O&M expenses applicable for the year in which the PSAdj will take effect. The Company shall annually adjust the O&M amount defined above by each year's PBR% defined below, and for a year in which a PSAdj will go into effect, the applicable O&M adjustment shall be included in the PSAdj.

PBR%: The annual Peformance-Based Ratemaking ("PBR") percentage increase applicable for the year in which the PSAdj will take effect.

PSAdj: The adjustment to the Local Production and Storage Cost Allowance to recover the Company's investment in its LNG facilities and O&M expense.

PT_{PS}: The property taxes calculated based on the cumulative net Production and Storage-related capital investment (CPS) at the end of the prior calendar year multiplied by the property tax rate approved by the Department in the Company's most recent base distribution rate case.

PY: Prior Year.

C: Current Year.

Peak Demand Factor (DFpci) Formula applicable to G-44B and G-54B:

$$DFpc = \frac{Dp - CCp + RApd - RApcc}{P{:}MDCQ} - R1d - R2d$$

and:

$$CCp = \text{Sum: } CM \times PR$$

Cost of Gas Adjustment Clause

Where:

Dp:	Demand Charges allocated to the peak period as defined in Section 6.05 and as determined for DFp above.
CCp:	Capacity Credits allocated to the peak period as defined in Section 6.05.
PR:	Proportional Responsibility Allocator as defined in section 6.05.
CM:	Economic Benefit derived from non-core sales as defined in section 6.05.
RApd:	Peak demand charge reconciliation adjustment - Account 175.20 balance, inclusive of the associated Account 175.20 interest, as outlined in section 6.08 and as determined for DFp above.
RApcc:	Peak capacity credit reconciliation adjustment - Account 175.56 balance, inclusive of the associated Account 175.56 interest, as outlined in section 6.08 and as determined for DFp above.
P:MDCQ:	Maximum Daily Contract Quantity for the peak period as defined in Section 6.05.
R1d, R2d:	Per unit supplier refunds from pipeline demand charges. The per-unit supplier refunds associated with refund program credits derived from Account 242.1, "Undistributed Gas Suppliers' Refunds". See section 6.07.

Peak Commodity Factor (CF) Formula:

$$CFp = \frac{Cp - COMp + I + RApc}{P{:}Sales} - R1c - R2c$$

and:

$$Cp = Sum{:}PC + BOao - INJ - LIQ$$

and:

$$BOao = BOop - (BOvol \times (TPop \div TPvolop))$$

Where:

Cp:	Commodity Charges allocated to the peak period as defined in Section 6.05.
COMp:	Commodity Credits allocated to the peak period as defined in Section 6.05.
I:	Inventory Finance Charges as defined in Section 6.05.
RApc:	Peak commodity charge reconciliation adjustment - Account 175.60 balance, inclusive of the associated Account 175.60 interest, as outlined in section 6.08.
P:Sales:	Forecasted sales volumes associated with the peak period.

Cost of Gas Adjustment Clause

PC: Commodity charges assigned to the peak period as defined in section 6.05.

INJ: Injections into storage.

LIQ: Liquefaction into storage.

BOao: LNG Boil-off allocation for the off-peak period.

BOop: LNG Boil-off charges for the off-peak period.

BOvol: LNG Boil-off volumes in the off-peak period

TPop: Total pipeline commodity charges for the off-peak period.

TPvolop: Total pipeline commodity volumes for the off-peak period.

R1c, R2c: Per unit supplier refunds from pipeline commodity charges- The per-unit supplier refunds associated with refund program credits derived from Account 242.2, "Undistributed Gas Suppliers' Refunds". See section 6.07.

Peak Bad Debt Formula:

$$BDFp = \frac{BDp + RApb}{P{:}\ Sales} + WCFpb$$

and:

$$WCFpb = \frac{\left(\frac{(WCApb \times CC) - (WCApb \times CD)}{(1 - TR)}\right) + (WCApb \times CD) + WCRpb}{P{:}Sales}$$

and:

$$WCApb = BDp \times (DL \div 365)$$

Where:

BDp: Peak Bad Debt Expense as defined in Section 6.05.

RApb: Peak Bad Debt Expense reconciliation adjustment - Account 175.52 balance.

P: Sales: Peak forecasted sales volumes.

WCFpb: Working Capital allowable per peak sales volume associated with bad debt allocated to the peak period as defined in Section 6.09.

WCApb: Peak Bad Debt allowable for working capital application as defined in section 6.09.

CC: Weighted Cost of Capital as defined in section 6.05.

CD: Weighted Cost of Debt as defined in section 6.05.

TR: Combined Tax Rate as defined in section 6.05.

Cost of Gas Adjustment Clause

WCRpb: Working Capital reconciliation adjustment associated with peak bad debt - Account 142.52 balance as outlined in section 6.09.

DL: Number of Days Lag from the purchase of gas from suppliers to the payment by customers.

Peak Gas Acquisition Expense Factor:

$$GAEFp = \frac{GAEp + RApo}{P{:}Sales}$$

Where

GAEp: Gas acquisition expenses associated with the procurement and transportation of commodity supplies in the peak period as defined in section 6.05.

P:Sales: Peak forecasted sales volumes.

RApo: Peak Gas Acquisition Expense reconciliation adjustment - Account 175.50 balance.

Peak Working Capital Factor:

$$WCFp = \frac{\dfrac{(WCAp \times CC) - (WCAp \times CD)}{(1 - TR)} + (WCAp \times CD) + WCRp}{P{:}Sales}$$

and:

$$WCAp = (Dp + Cp + GAEp) \times (DL \div 365)$$

and:

$$Dp = \frac{Dp \times P{:}Sales}{P{:}Sales}$$

and:

$$Cp = \frac{Cp \times P{:}Sales}{P{:}Sales}$$

Where:

Dp: Demand Charges allocated to the peak period as defined in Section 6.05.

Cp: Commodity Charges allocated to the peak period as defined in Section 6.05.

P:Sales: Forecasted billed sales volumes associated with the peak period.

Cost of Gas Adjustment Clause

WCFp:	Working Capital allowable per billed peak through put volume associated with demand and commodity charges allocated to the peak period as defined in Section 6.09.
WCAp:	Demand and commodity charges allowable for working capital application as defined in section 6.09.
CC:	Weighted Cost of Capital as defined in section 6.05.
CD:	Weighted Cost of Debt as defined in section 6.05.
TR:	Combined Tax Rate as defined in section 6.05.
WCRp:	Working Capital reconciliation adjustment associated with peak charges – (Account 142.20 balance) as outlined in section 6.09.
DL:	Number of Days Lag from the purchase of gas from suppliers to the payment by customers.
GAEp:	Gas Acquisition Expenses associated with the procurement and transportation of commodity supplies in the peak period as defined in section 6.05.

Off-Peak GAF Formula:

The Off-Peak GAF (excluding that applicable to General Service Rates G-44B and G-54B) shall be comprised of an off-peak demand factor, an off-peak commodity factor, an off peak bad debt factor, an off peak gas acquisition expense factor, and an off peak working capital factor calculated at the beginning of the Off-Peak Season according to the following formula:

$$GAFop = DFop + CFop + BDFop + GAEFop + WCFop$$

The Off-Peak GAFs applicable to General Service Rates G-44B and G-54B shall be comprised of an off-peak demand factor to be applied to the customer's off-peak Maximum Daily Contract Quantity and an off-peak commodity factor, an off-peak bad debt factor, an off-peak gas acquisition expense factor, and an off-peak working capital factor to be applied to the customer's monthly consumption, calculated at the beginning of the Off-Peak Season according to the following formulae:

$$GAF1op = DFopc$$

$$GAF2op = CFop + BDFop + GAEFop + WCFop$$

Off-Peak Demand Factor (DFop) Formula:

$$DFop = \frac{Dop - CCop + RAopd - RAopcc}{OP{:}Sales} - R1d - R2d$$

and:

$$Dop = \text{Sum: } AD \times (1 - PR)$$

Cost of Gas Adjustment Clause

and:

CCop = Sum: CM x (1- PR)

Where:

Dop: Demand charges allocated to the off-peak period as defined in section 6.05.

CCop: Capacity Credits allocated to the off peak period as defined in Section 6.05.

PR: Proportional Responsibility Allocator as defined in section 6.05.

CM: Economic benefit derived from non-core sales as defined in section 6.05.

RAopd: Off-peak demand charge reconciliation adjustment - Account 175.40 balance, inclusive of the associated Account 175.40 interest, as outlined in section 6.08.

RAopcc: Off-peak capacity credit reconciliation adjustment - Account 175.58 balance, inclusive of the associated Account 175.58 interest, as outlined in section 6.08.

OP:Sales: Forecasted billed sales volumes associated with the off-peak period.

AD: Demand charges billed to the Company for year round capacity as defined in section 6.05.

R1d, R2d: Per unit supplier refunds from pipeline demand charges. The per-unit supplier refunds associated with refund program credits derived from Account 242.1, "Undistributed Gas Suppliers' Refunds." See section 6.07.

Off-Peak Demand Factor (DFopci) Formula applicable to G-44B and G-54B:

$$\text{DFopc} = \frac{\text{Dop - CCop + RAopd - RAopcc}}{\text{OP:MDCQ}} - \text{R1d - R2d}$$

and:

CCop = Sum: CM x (1- PR)

Where:

Dop: Demand Charges allocated to the off-peak period as defined in Section 6.05 and as determined for DFop above.

CCop: Capacity Credits allocated to the off peak period as defined in Section 6.05.

PR: Proportional Responsibility allocator as defined in section 6.05.

CM: Economic benefit derived from non-core sales as defined in section 6.05.

Cost of Gas Adjustment Clause

RAopd: Off-Peak demand charge reconciliation adjustment - Account 175.20 balance, inclusive of the associated Account 175.40 interest, as outlined in section 6.08 and as determined for DFop above.

RAopcc: Off-Peak capacity credit reconciliation adjustment - Account 175.58 balance, inclusive of the associated Account 175.58 interest, as outlined in section 6.08 and as determined for DFop above.

OP:MDCQ: Maximum Daily Contract Quantity for the off-peak period as defined in Section 6.05.

R1d, R2d: Per unit supplier refunds from pipeline demand charges. The per-unit supplier refunds associated with refund program credits derived from Account 242.1, "Undistributed Gas Suppliers' Refunds." See section 6.07.

<u>Off-Peak Commodity Factor (CFop) Formula:</u>

$$CFop = \frac{Cop - COMop + RAopc}{OP{:}Sales} - R1c - R2c$$

and:

$$Cop = \text{Sum: } OPC - BOao - INJ - LIQ$$

and:

$$BOao = BOop - (BOvol \times (TPop \div TPvolop))$$

Where:

Cop: Commodity Charges billed to the off-peak period as defined in Section 6.05.

COMop: Commodity Credits allocated to the off-peak period as defined in Section 6.05.

RAopc: Off peak commodity charge reconciliation adjustment - Account 175.80 balance, inclusive of the associated Account 175.80 interest, as outlined in section 6.08.

OP:Sales: Forecasted sales volumes associated with the off-peak period.

OPC: Commodity charges assigned to the off-peak period as defined in section 6.05.

BOao: LNG Boil-off allocation for the off-peak period.

BOop: LNG Boil-off charges for the off-peak period.

BOvol: LNG Boil-off volumes in the off-peak period.

INJ: Injections into storage.

LIQ: Liquefaction into storage.

Cost of Gas Adjustment Clause

TPop: Total pipeline commodity purchase charges for the off-peak period.

TPvolop: Total pipeline purchase volumes for the off-peak period.

R1c, R2c: Per unit supplier refunds from pipeline commodity charges. The per-unit supplier refunds associated with refund program credits derived from Account 242.2, "Undistributed Gas Suppliers' Refunds." See section 6.07.

Off Peak Bad Debt Formula:

$$BDFop = \frac{BDop + RAopb}{OP: Sales} + WCFopb$$

and:

$$WCFopb = \frac{\frac{(WCAopb \times CC) - (WCAopb \times CD)}{(1 - TR)} + (WCAopb \times CD) + WCRopb}{OP:Sales}$$

and:

$$WCAopb = BDop \times (DL \div 365)$$

Where:

BDop: Off Peak Bad Debt Expense as defined in Section 6.05.

RAopb: Off Peak Bad Debt Expense reconciliation adjustment - Account 175.54 balance.

OP: Sales: Off Peak forecasted sales volumes.

WCFopb: Working Capital allowable per Off Peak sales volume associated with commodity charges allocated to the Off Peak period as defined in Section 6.09.

WCAopb Bad Debt allowable for working capital application as defined in section 6.09.

CC: Weighted Cost of Capital as defined in section 6.05.

CD: Weighted Cost of Debt as defined in section 6.05.

TR: Combined Tax Rate as defined in section 6.05.

WCRopb Working Capital reconciliation adjustment associated with Off Peak bad debt - Account 142.54 balance as outlined in section 6.09.

DL: Number of days lag from the purchase of gas from suppliers to the payment by customers.

Cost of Gas Adjustment Clause

Off Peak Gas Acquisition Expense Factor:

$$GAEFop = \frac{GAEop + RAopo}{OP{:}Sales}$$

Where:

GAEop: Gas acquisition expenses associated with the procurement and transportation of commodity supplies in the Off Peak period as defined in section 6.05.

OP:Sales: Off Peak forecasted sales volumes.

RAopo: Off Peak Gas Acquisition Expense reconciliation adjustment - Account 175.70 balance.

Off Peak Working Capital Factor:

$$WCFop = \frac{\dfrac{(WCAop \times CC) - (WCAop \times CD)}{(1 - TR)} + (WCAop \times CD) + WCRop}{OP{:}Sales}$$

and:

$$WCAop = (Dop + Cop + GAEop) \times (DL \div 365)$$

and:

$$Dop = \frac{Dop \times OP{:}Sales}{OP{:}Sales}$$

and:

$$Cop = \frac{Cop \times OP{:}Sales}{OP{:}Sales}$$

Where:

Dop: Demand Charges allocated to the Off Peak period as defined in Section 6.05.

Cop: Commodity Charges allocated to the Off Peak period as defined in Section 6.05.

Dop: Demand Charges allocated to the Off Peak period as defined in Section 6.05.

Cop: Commodity Charges allocated to the Off Peak period as defined in Section 6.05.

OP:Sales: Forecasted billed sales volumes associated with the Off Peak period.

Cost of Gas Adjustment Clause

WCFop: Working Capital allowable per billed Off Peak through put volume associated with demand and commodity charges allocated to the Off Peak period as defined in Section 6.09.

WCAop: Demand and commodity charges allowable for working capital application as defined in section 6.09.

CC: Weighted Cost of Capital as defined in section 6.05.

CD: Weighted Cost of Debt as defined in section 6.05.

TR: Combined Tax Rate as defined in section 6.05.

WCRop: Working Capital reconciliation adjustment associated with Off Peak charges – (Account 142.40 balance) as outlined in section 6.09.

DL: Number of Days Lag from the purchase of gas from suppliers to the payment by customers.

GAEop: Gas Acquisition expenses associated with the procurement and transportation of commodity supplies in the Off Peak period as defined in section 6.05.

6.07 Gas Suppliers' Refunds - Accounts 242.1 and 242.2

Refunds from suppliers of capacity are credited to account 242.1, "Undistributed Purchased Capacity Refunds." Refunds from suppliers of gas and feed stocks are credited to account 242.2, "Undistributed Gas Suppliers' Refunds." Refunds associated with FERC Order 636 transition costs will not be credited to either 242 accounts, but will be credited directly to Account 175.46 - Transition Costs. Transfers from accounts 242.1 and 242.2 will be reflected as a credit in the semiannual calculation of the GAF to be calculated as follows:

Refund programs shall be initiated with each semiannual GAF filing and shall remain in effect for a period of one year. The total dollars to be placed into a given refund program shall be net of over/under-returns from expired programs plus moneys received from suppliers since the previous program was initiated. Moneys to be refunded through each program shall be segregated by demand and commodity charges and distributed volumetrically, producing per-unit refund factors that will return the principal amount with interest as calculated using the prime lending rate. The Company shall track and report all account 242.1 and account 242.2 activities as specified in Section 6.11.

6.08 Reconciliation Adjustments - Account 175

(1) The following definitions pertain to reconciliation adjustment calculations:

(a) Capacity Costs Allowable Per Peak Demand Formula shall be:

i. Charges associated with upstream storage and transmission capacity procured by the Company to serve firm load in the Peak Season (PD).

ii. Charges associated with upstream storage and transmission capacity procured by the Company to serve firm load year round and allocated to the peak by applying the total firm proportional responsibility allocator for the peak period from the Company's most recent base distribution rate case (AD x PR).

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iii. Charges associated with local production and storage capacity in service to serve firm load in the Peak Season from the Company's most recent test year multiplied by the percentage allocated to sales storage service (PS x PSP).
iv. Account 175.20 - Peak demand, interest charges.

(b) Gas Costs Allowable Per Peak Commodity Formula shall be:
i. Charges associated with gas supplies, including any applicable taxes, purchased by the Company to serve firm load in the Peak Season, plus a reallocation of LNG boiloff costs from the Off-Peak Season, determined by the product of the difference in the average cost of pipeline purchases during the off-peak period and the average cost of LNG boiloff in the off-peak period times the LNG boiloff volumes purchased in the off-peak period, less the cost of injections and liquefaction into storage (Cp).
ii. Peak commodity credits allocated for gas costs sent out to serve non-firm customers to which the CGAC does not apply, as defined in section 6.05 (COMp).
iii. Inventory finance charges (I).
iv. Account 175.60 - Peak commodity, interest charges.

(c) Capacity Costs Allowable Per Off-Peak Demand Formula shall be:
i. Charges associated with upstream storage and transmission capacity procured by the Company to serve firm load year round and allocated to the off-peak by applying the total firm proportional responsibility allocator for the off- peak period from the Company's most recent base distribution rate case (AD x (1-PR)).
ii. Account 175.40 – Off-Peak demand, interest charges.

(d) Gas Costs Allowable Per Off-Peak Commodity Formula shall be:
i. Charges associated with gas supplies, including any applicable taxes, procured by the Company to serve firm load in the Off-Peak Season, less the reallocation of LNG boiloff costs determined by the product of the difference in the average cost of pipeline purchases during the off-peak period and the average cost of LNG boiloff in the off-peak period times the LNG boiloff volumes purchased in the off-peak period, less the cost of injections and liquefaction into storage (Cop).
ii. Off-Peak commodity credits allocated for gas costs sent out to serve non-firm customers to which the CGAC does not apply, as defined in section 6.05 (COMp).
iii. Account 175.80 - Off-Peak commodity, interest charges.

(e) Costs Allowable Per Peak Bad Debt Formula shall be:
i. Costs associated with uncollected gas costs, including any applicable taxes, incurred by the Company to serve firm load in the Peak Season.
ii. Account 175.52 - Peak Bad Debt, interest charges.

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(f) Costs Allowable Per Off-Peak Bad Debt Formula shall be:
  i. Costs associated with uncollected gas costs, including any applicable taxes, incurred by the Company to serve firm load in the Off-Peak Season.
  ii. Account 175.54 - Off-Peak Bad Debt, interest charges.

(g) Credits Allowable Per Peak Capacity Credit Formula shall be:
  i. Credits associated with the Economic Benefits derived from the noncore sale of gas refunded to core customers by the Company in the Peak Season.
  ii. Account 175.56 - Peak Capacity Credits, interest charges.

(h) Credits Allowable Per Off-Peak Capacity Credit Formula shall be:
  i. Credits associated with the economic benefits derived from the noncore sale of gas refunded to core customers by the Company in the Off-Peak Season.
  ii Account 175.58 - Off-Peak Capacity Credits, interest charges.

(i) Costs Allowable Per Peak Gas Acquisition Expense Formula shall be:
  i. Charges associated with gas acquisition expenses incurred to procure and transport gas supplies to serve firm load in the Peak Season from the Company's most recent test year (GAE).
  ii. Account 175.50 - Peak Gas Acquisition Expenses, interest charges.

(j) Costs Allowable Per Off-Peak Gas Acquisition Expense Formula shall be:
  i. Charges associated with gas acquisition expenses incurred to procure and transport gas supplies to serve firm load in the Off-Peak Season from the Company's most recent test year (GAE).
  ii. Account 175.70 - Off-Peak Gas Acquisition Expenses, interest charges.

(k) WACOD (Weighted Average Cost of Demand) equals the demand factor for each season (DFp and DFop) as computed in section 6.06. This figure is used as the convention for recognizing revenues toward each season's demand costs.

(l) WACCOG (Weighted Average Commodity Cost of Gas) equals the commodity factor for each season as computed in section 6.06. This figure is used as the convention for recognizing revenues toward each season's commodity costs.

(m) MDCQ demand equals the demand factor for G-44B and G-54B each season (DFpc and DFopc) as computed in section 6.06. This figure is used as the convention for recognizing revenues from G-44B and G-54B toward each season's demand costs.

(2) Calculation of the Reconciliation Adjustments

Account 175 contains the accumulated difference between gas cost revenue and the actual monthly gas costs incurred by the Company. The Company shall separate Account 175 into peak demand (Account 175.20), peak commodity (Account 175.60), off-peak demand (Account 175.40), off-peak commodity (Account 175.80), peak bad debt (Account 175.52), off-peak bad debt (Account 175.54), peak capacity credit (Account 175.56), off-

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peak capacity credit (Account 175.58), peak gas acquisition expense (Account 175.50), and off-peak gas acquisition expense (Account 175.70). Account 175.20 shall contain the accumulated difference between revenue toward capacity costs as calculated by multiplying the peak WACOD times monthly firm through put volumes (excluding G-44B and G-54B) summed with the peak MDCQ demand for G-44B and G-54B times the MDCQ each month and capacity costs allowable per peak demand formula. Account 175.60 shall contain the accumulated difference between revenue toward gas costs as calculated by multiplying the peak WACCOG times monthly firm sales volumes and gas costs allowed per peak commodity formula. Account 175.40 shall contain the accumulated difference between revenue toward capacity costs as calculated by multiplying the off-peak WACOD times monthly firm through put volumes (excluding G-44B and G-54B) summed with the off-peak MDCQ demand for G-44B and G-54B times the MDCQ each month throughput volumes and capacity costs allowable per off-peak demand formula. Account 175.80 shall contain the accumulated difference between revenue toward gas costs as calculated by multiplying the off-peak WACCOG times monthly firm sales volumes and gas costs allowed per off-peak commodity formula.

Account 175.52 shall contain the accumulated difference between revenue toward bad debt as calculated by multiplying the peak bad debt factor times monthly firm sales volumes and bad debt allowed per peak bad debt formula. Account 175.54 shall contain the accumulated difference between revenue toward bad debt as calculated by multiplying the off-peak bad debt factor times monthly firm sales volumes and bad debt allowed per off-peak bad debt formula.

Account 175.50 shall contain the accumulated difference between revenue toward gas acquisition expense as calculated by multiplying the peak gas acquisition expense factor times monthly firm sales volumes and gas acquisition expense allowed per peak gas acquisition formula. Account 175.70 shall contain the accumulated difference between revenue toward gas acquisition expense as calculated by multiplying the off-peak gas acquisition expense factor times monthly firm sales volumes and gas acquisition expense allowed per off-peak other gas supply formula.

The peak demand reconciliation adjustment (RApd - as defined in Section 6.06) shall be determined for use in the peak GAF calculations incorporating the peak demand account (175.20) balance as of the peak reconciliation date as designated by the Company. The peak commodity reconciliation adjustment (RApc - as defined in Section 6.06) shall be determined for use in the peak GAF calculations incorporating the peak commodity account (175.60) balance as of the peak reconciliation date as designated by the Company. The off-peak demand reconciliation adjustment (RAopd - as defined in Section 6.06) shall be determined for use in the off-peak GAF calculations incorporating the off-peak demand account (175.40) balance as of the off-peak reconciliation date as designated by the Company. The off-peak commodity reconciliation adjustment (RAopc - as defined in Section 6.06) shall be determined for use in the off-peak GAF calculations incorporating the off-peak commodity account (175.80) balance as of the off-peak reconciliation date as designated by the Company.

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The peak bad debt reconciliation adjustment (RApb - as defined in Section 6.06) shall be determined for use in the peak GAF calculations incorporating the peak bad debt account (175.52) balance as of the peak reconciliation date as designated by the Company. The off-peak bad debt reconciliation adjustment (RAopb - as defined in Section 6.06) shall be determined for use in the off-peak GAF calculations incorporating the off-peak bad debt account (175.54) balance as of the off-peak reconciliation date as designated by the Company. The peak capacity reconciliation adjustment (RApcc - as defined in Section 6.06) shall be determined for use in the peak GAF calculations incorporating the peak capacity credit account (175.56) balance as of the peak reconciliation date as designated by the Company. The off-peak capacity reconciliation adjustment (RAopcc - as defined in Section 6.06) shall be determined for use in the off-peak GAF calculations incorporating the off-peak capacity account (175.58) balance as of the off-peak reconciliation date as designated by the Company. The peak gas acquisition reconciliation adjustment (RApo - as defined in Section 6.06) shall be determined for use in the peak GAF calculations incorporating the peak gas acquisition account (175.50) balance as of the peak reconciliation date as designated by the Company. The off-peak gas acquisition reconciliation adjustment (RAopo - as defined in Section 6.06) shall be determined for use in the off-peak GAF calculations incorporating the off-peak gas acquisition account (175.70) balance as of the off-peak reconciliation date as designated by the Company.

6.09 Reconciliation Adjustments - Account 142 Working Capital

(1) The following definitions pertain to reconciliation adjustment calculations:

(a) Working Capital Gas Costs Allowable Per Peak Formula shall be:

i. Charges associated with upstream storage and transmission capacity procured by the Company to serve firm load in the Peak Season (PD).

ii. Charges associated with upstream storage and transmission capacity procured by the Company to serve firm load year round and allocated to the peak by applying the total firm proportional responsibility allocator for the peak period from the Company's most recent base distribution rate case (AD x PR).

iii. Charges associated with local production and storage capacity in service to serve firm load in the Peak Season as approved by the Department times the percent allocated to sales storage service (PS x PSP).

iv. Charges associated with gas supplies, including any applicable taxes, purchased by the Company to serve firm load in the Peak Season, plus a reallocation of LNG boiloff costs from the Off-Peak Season, determined by the product of the difference in the average cost of pipeline purchases during the off-peak period and the average cost of LNG boiloff in the off-peak period times the LNG boiloff volumes purchased in the off-peak period, less the cost of injections and liquefaction into storage.

v. Charges associated with gas acquisition expenses incurred to procure and transport gas supplies to serve firm load in the Peak Season from the Company's most recent test year (GAEp).

vi. Charges associated with capacity credits refunded by the Company to serve firm load in the peak period.

vii. Account 142.20 interest charges.

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(b) Working Capital Gas Costs Allowable Per Off-Peak Formula shall be:

i. Charges associated with upstream storage and transmission capacity procured by the Company to serve firm load year round and allocated to the off-peak by applying the total firm proportional responsibility allocator for the off-peak period from the Company's most recent base distribution rate case (Dop).

ii. Charges associated with gas supplies, including any applicable taxes, procured by the Company to serve firm load in the Off-Peak Season, less the reallocation of LNG boiloff costs determined by the product of the difference in the average cost of pipeline purchases during the off-peak period and the average cost of LNG boiloff in the off-peak period.

iii. Charges associated with gas acquisition expenses incurred to procure and transport gas supplies to serve firm load in the Off-Peak Season from the Company's most recent test year (GAEop).

iv. Charges associated with capacity credits refunded by the Company to serve firm load in the off peak period.

v. Account 142.40 interest charges.

(c) Working Capital Gas Costs Allowable Per Peak Bad Debt Formula shall be:

i. Charges associated with bad debt incurred by the Company to serve firm load in the peak period.

ii. Account 142.52 interest charges.

(d) Working Capital Gas Costs Allowable Per Off-Peak Bad Debt Formula shall be:

i. Charges associated with bad debt incurred by the Company to serve firm load in the off-peak period.

ii. Account 142.54 interest charges.

(2) The peak and off-peak gas cost and bad debt cost working capital requirements shall be calculated by applying the Company's days lag divided by 365 days to the working capital costs allowable per each formula defined in sections (a), (b), (c), and (d).

(3) The peak and off-peak gas cost and bad debt working capital allowances shall each be calculated by applying the Company's weighted cost of capital requirement to calculate the respective returns on working capital. The interest portion of each working capital allowance is calculated by multiplying each working capital requirement by the Company's weighted cost of debt. The return on each working capital less the interest portion of each working capital is then divided by one minus the tax rate. This figure plus the interest calculated above equals the working capital allowance for each.

(4) Calculation of the Reconciliation Adjustments

Accounts 142.20, 142.40, 142.52, and 142.54 contain the accumulated difference between working capital allowance revenue and the actual monthly working capital allowance costs as calculated from actual monthly costs for the Company. The components of the Company's purchased gas days lag shall be recalculated each season based upon actual

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CGAC seasonal data. This recalculated days lag will be used in the calculation of the working capital allowance revenue. Each Account 142 shall contain the accumulated difference between revenues toward the working capital allowance and the working capital allowance.

A peak working capital reconciliation adjustment (WCRp - as defined in Section 6.06) shall be determined for use in the peak factor calculations incorporating the peak working capital account (142.20) balance as of the peak reconciliation date designated by the Company. An off-peak working capital reconciliation adjustment (WCRop - as defined in Section 6.06) shall be determined for use in the off-peak factor calculations incorporating the off-peak working capital account (142.40) balance as of the off-peak reconciliation date designated by the Company.

A peak bad debt working capital reconciliation adjustment (WCRpb - as defined in Section 6.06) shall be determined for use in the peak bad debt factor calculations incorporating the peak bad debt working capital account (142.52) balance as of the peak reconciliation date designated by the Company. An off-peak bad debt working capital reconciliation adjustment (WCRopb - as defined in Section 6.06) shall be determined for use in the off-peak bad debt factor calculations incorporating the off-peak bad debt working capital account (142.54) balance as of the off-peak reconciliation date designated by the Company.

6.10 <u>Application of GAF to Bills</u>

The Company will employ the GAFs as follows:

(1) <u>For Sales Customers</u> (excluding G-44B and G-54B) - The Peak Season rates to customers shall be calculated by adding the peak demand factor, the peak commodity factor, the peak working capital factor, the peak gas acquisition expense factor, and the peak bad debt factor. The Off-Peak Season rates to customers shall be calculated by adding the off-peak demand factor, the off-peak commodity factor, the off peak working capital factor, the off peak gas acquisition expense factor, and the off peak bad debt factor. The seasonal GAFs ($/therm) shall be calculated to the nearest hundredth of a cent per unit and will be applied to each customer's monthly sales volumes.

(2) <u>For General Service Rates G-44B and G-54B customers</u> - The Peak Season demand factor will be applied monthly to each customer's peak Maximum Daily Contract Quantity. The Peak Season volumetric factor shall equal the sum of the peak commodity factor, the peak working capital factor, the peak gas acquisition expense factor, and the peak bad debt factor. The Off-Peak Season demand factor will be applied monthly to each customer's off-peak Maximum Daily Contract Quantity. The Off-Peak Season volumetric factor shall equal the sum of the off-peak commodity factor, the off-peak working capital factor, the off-peak gas acquisition expense factor, and the off-peak bad debt factor. The volumetric factor will be applied to each customer's monthly sales volumes. The seasonal GAFs ($/therm) shall be calculated to the nearest hundredth of a cent per unit.

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6.11 Information Required to be Filed with the Department

Information pertaining to the cost of gas adjustment shall be filed with the Department in accordance with the standardized forms approved by the Department. Required filings include a monthly report which shall be submitted to the Department on the twentieth of each month, and a semiannual GAF filing which shall be submitted to the Department at least 45 days before the date on which a new GAF is to be effective.

Additionally, the Company shall file with the Department a complete list by (sub)account of all gas costs claimed as recoverable through the CGAC over the previous season, as included in the seasonal reconciliation. This information shall be submitted with each seasonal GAF filing, along with complete documentation of the reconciliation adjustment calculations.

Additionally, in the year in which the Company petitions the Department for an adjustment to its Local Production and Storage Allowance, the Company shall notify the Department in writing by May 1 of its intention to make a filing during that year; and file with the Department by June 15 testimony and relevant exhibits, including, but not limited to,

(i) Capital project details summary sheet and index;
(ii) Calendar year charges to in-service projects;
(iii) Project documentation including a project title page, project authorization, and project authorization detail form supporting the LNG investment placed into service since March 31, 2020 through the end of the prior calendar year,
(iv) Closure reports;
(v) Variance analysis, where applicable;
(vi) Blanket authorizations;
(vii) Summary list of invoices and related cost per project; and
(viii) Variance analysis on calendar year charages to in-service projects, where applicable.

For each project, the Company shall also provide a detailed justification and alternatives anslyses for why a full replacement was necessary instead of a less expensive strategy. The Company shall also calculate the revenue requirement associated with the LNG investment to adjust the then-current Local Production and Storage Allowance, with the updated Local Production and Storage Allowance to be recovered beginning with the Company's subsequent peak GAF.

6.12 Other Rules

(1) The Department may where appropriate, on petition or on its own motion, grant an exception from the provisions of these regulations, upon such terms that it may determine to be in the public interest.

(2) The Company may, at any time, file with the Department an amended GAF. An amended GAF filing must be submitted seven (7) business days before the first billing cycle of the month in which it is proposed to take effect.

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(3) The Department may at any time require the Company to file an amended GAF.

(4) The operation of the CGAC is subject to all powers of suspension and investigation vested in the Department by G.L. c. 164.

(5) Pursuant to the Department’s directives in Cost of Gas Adjustment Clause, D.T.E. 01-49-A (October 9, 2001), the Company will file an amended GAF when it is determined that the projected deferred gas cost balance at the end of the season exceeds the projected gas costs by five (5) percent.

6.13 Customer Notification

The Company will notify customers in simple terms of changes to the GAF, including the nature of the change and the manner in which the GAF is applied to the bill. In the absence of a standard format, the Company will submit this notice for approval at the time of each GAF filing. Upon approval by the Department, the Company must immediately distribute these notices to all of its customers either through direct mail or with its bills.

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AMENDMENTS TO
UNIFORM SYSTEM OF ACCOUNTS FOR GAS COMPANIES

175.20 Peak Demand Reconciliation Adjustment for CGAC
This account shall be used to record the cumulative difference between peak demand gas revenues and peak demand gas costs. Entries to this account shall be determined as outlined in the Cost of Gas Adjustment Clause, 220 C.M.R. 6.09.

175.40 Off-Peak Demand Reconciliation Adjustment for CGAC
This account shall be used to record the cumulative difference between off-peak demand gas revenues and off-peak demand gas costs. Entries to this account shall be determined as outlined in the Cost of Gas Adjustment Clause, 220 C.M.R. 6.09.

175.50 Peak Gas Acquisition Expense Reconciliation Adjustment for CGAC
This account shall be used to record the cumulative difference between peak gas acquisition expense revenues and peak gas acquisition expense costs. Entries to this account shall be determined as outlined in the Cost of Gas Adjustment Clause, 220 C.M.R. 6.09.

175.52 Peak Bad Debt Reconciliation Adjustment for CGAC
This account shall be used to record the cumulative difference between peak bad debt revenues and peak bad debt costs. Entries to this account shall be determined as outlined in the Cost of Gas Adjustment Clause, 220 C.M.R. 6.09.

175.54 Off-Peak Bad Debt Reconciliation Adjustment for CGAC
This account shall be used to record the cumulative difference between off-peak bad debt revenues and off-peak bad debt costs. Entries to this account shall be determined as outlined in the Cost of Gas Adjustment Clause, 220 C.M.R. 6.09.

175.56 Peak Capacity Credit Reconciliation Adjustment for CGAC
This account shall be used to record the cumulative difference between peak capacity credits refunds and peak capacity credits allowed. Entries to this account shall be determined as outlined in the Cost of Gas Adjustment Clause, 220 C.M.R. 6.09.

175.58 Off-Peak Capacity Credit Reconciliation Adjustment for CGAC
This account shall be used to record the cumulative difference between off-peak capacity credits refunds and off-peak capacity credits allowed. Entries to this account shall be determined as outlined in the Cost of Gas Adjustment Clause, 220 C.M.R. 6.09.

175.60 Peak Commodity Reconciliation Adjustment for CGAC
This account shall be used to record the cumulative difference between peak commodity gas revenues and peak commodity gas costs. Entries to this account shall be determined as outlined in the Cost of Gas Adjustment Clause, 220 C.M.R. 6.09.

175.70 Off-Peak Gas Acquisition Expense Reconciliation Adjustment for CGAC
This account shall be used to record the cumulative difference between off-peak gas acquisition expense revenues and off-peak gas acquisition expense costs. Entries to this

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account shall be determined as outlined in the Cost of Gas Adjustment Clause, 220 C.M.R. 6.09.

175.80 Off-Peak Commodity Reconciliation Adjustment for CGAC
This account shall be used to record the cumulative difference between off-peak commodity gas revenues and off-peak commodity gas costs. Entries to this account shall be determined as outlined in the Cost of Gas Adjustment Clause, 220 C.M.R. 6.09.

142.20 Peak Gas Cost Working Capital Allowance Reconciliation Adjustment for CGAC
This account shall be used to record the cumulative difference between peak gas cost working capital allowance revenues and peak gas cost working capital allowance. Entries to this account shall be determined as outlined in the Cost of Gas Adjustment Clause, 220 C.M.R. 6.10.

142.40 Off-Peak Gas Cost Working Capital Allowance Reconciliation Adjustment for CGAC
This account shall be used to record the cumulative difference between off-peak gas cost working capital allowance revenues and off-peak gas cost working capital allowance. Entries to this account shall be determined as outlined in the Standard Cost of Gas Adjustment Clause, 220 C.M.R. 6.10.

142.52 Peak Bad Debt Gas Working Capital Allowance Reconciliation Adjustment for CGAC
This account shall be used to record the cumulative difference between peak bad debt working capital allowance revenues and peak bad debt working capital allowance. Entries to this account shall be determined as outlined in the Cost of Gas Adjustment Clause, 220 C.M.R. 6.10.

142.54 Off-Peak Bad Debt Gas Working Capital Allowance Reconciliation Adjustment for CGAC
This account shall be used to record the cumulative difference between off-peak bad debt working capital allowance revenues and off-peak bad debt working capital allowance. Entries to this account shall be determined as outlined in the Cost of Gas Adjustment Clause, 220 C.M.R. 6.10.

242.10 Undistributed Capacity Suppliers' Refunds
This account will be used to record the refunds from suppliers of pipeline capacity. Entries to this account shall be determined as outlined in the Cost of Gas Adjustment Clause, 220 C.M.R. 6.07.

242.20 Undistributed Gas Suppliers' Refunds
This account will be used to record the refunds from suppliers of gas and feed stocks. Entries to this account shall be determined as outlined in the Cost of Gas Adjustment Clause, 220 C.M.R. 6.07.

Local Distribution Adjustment Clause

Section

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6.01 Purpose

The purpose of the Local Distribution Adjustment Clause ("LDAC") is to establish a procedure that allows Boston Gas Company d/b/a National Grid (the "Company"), subject to the jurisdiction of the Department of Public Utilities (the "Department") to adjust, on an annual basis, its rates to recover costs associated with (1) Energy Efficiency ("EE") programs and related working capital, (2) Environmental Response Costs associated with manufactured gas plants, (3) Attorney General Consultant Expenses, (4) Pension and Post-Retirement Benefits Other than Pensions costs, (5) Residential Assistance costs, (6) the Gas System Enhancement Program, (7) the Gas Business Enablement Program, and (8) the Geothermal District Energy Demonstration Program, and to credit all core customers with (1) the Economic Benefit associated with interruptible transportation service that is not included in the base distribution rates as determined in the Company's last base distribution rate case, (2) Service Quality Penalties assessed in accordance with a Department approved service quality plan, (3) balancing penalty revenues to all firm customers, and (4) customers' share of excess earnings in accordance with the Earnings Sharing Mechanism pursuant to the Company's Performance-Based Ratemaking Tariff, M.D.P.U. No. 93.1, as may be amended from time to time.

6.02 Applicability

The LDAC applies to all tariff throughput volumes on the Company's system, except as otherwise designated herein. See Section 6.19, "Other Rules".

6.03 Energy Efficiency Costs

Energy Efficiency Costs eligible for recovery will include all costs as defined and approved by the Department for a twelve month period as contained in the Company's Energy Efficiency budgets, including: (1) Energy Efficiency Program and Market Transformation Costs; (2) Energy Efficiency Incentives; (3) Energy Efficiency-related pension and post retirement benefits other than pension costs; and (4) Working Capital allowances for EE costs. Energy Efficiency Costs Allowable for LDAC recovery will include Energy Efficiency Program and Market Transformation Costs incurred by the Company to provide EE to the customers of Blackstone Gas Company and associated performance incentives. At the end of each twelve month period, the Company will include the Reconciliation Adjustment associated with over or under recoveries of allowable EE costs billed over the prior twelve month period.

6.04 Environmental Response Costs

All Environmental Response Costs associated with manufactured gas plants, adjusted for deferred tax benefits, and one-half of the expenses incurred by the Company in pursuing insurance and third party claims, less one half of the recoveries received by the Company and as a result of such claims may be included in the LDAC.

6.05 Attorney General Consultant Expenses

All Attorney General Consultant Expenses associated with the Attorney General's retention of consultants to assist with cases before the Department pursuant to M.G.L. Chapter 12, Section 11E(b) and Section 4 of Chapter 169 of the Acts of 2008 ("Green Communities Act") enacted and signed into law on July 2, 2008. Such Department-approved expenses are recognized as proper business expenses recoverable through the LDAC.

6.06 Pension and Post-Retirement Benefits Other Than Pensions Costs

All non-capitalized costs associated with pensions and post-retirement benefits other than pensions ("PBOPs"), excluding Energy Efficiency-related pension and PBOP costs effective January 1, 2016, and the reconciliation of each year's actuarial forecast of pension and PBOP expense amounts included in the Company's LDAC with the total expense amounts booked by the Company pursuant to FASB Accounting Standards Codification Topic 715 – Compensation – Retirement Benefits ("ASC 715") may be included in the LDAC as approved by the Department.

6.07 Service Quality Penalty

Any service quality penalties assessed to Boston Gas Company or the former Colonial Gas Company pursuant to each company's service quality plan approved by the Department will be included in the LDAC as a credit to the customers located in each of the respective areas served by Boston Gas Company and the former Colonial Gas Company prior to their merger.

6.08 Residential Assistance Adjustment Costs

The amount of incremental costs related to the Company's approved Arrearage Residential Management Program ("AMP") as approved by the Department and the low income discount will be included in the LDAC and recovered through the Residential Assistance Adjustment Factors

("RAAF"). The level of discount and associated reduced or discounted revenue is set at a fixed percentage of total bill. The total bill discount percentages are as follows:

- Residential Assistance Non-Heating, R-2, 25%
- Residential Assistance Heating, R-4, 25%

The associated reduced or discounted revenue shall be equal to the fixed percentage applied to the calculated total bill of all customers taking service under the low-income tariff rates (R-2 and R-4).

6.09 Gas System Enhancement Program Costs

The annual recovery of the annual Revenue Requirements associated with the replacement or improvement of existing natural gas distribution infrastructure to improve public safety or infrastructure reliability subject to the review and approval of the Department, will be included in the LDAC. In accordance with G.L. c. 164, § 145(b), all costs associated with the GSEP are incurred to address aging or leaking natural gas infrastructure within the Commonwealth in the interest of public safety and reducing lost and unaccounted for natural gas through a reduction in natural gas system leaks. Consistent with St. 2016. c. 188, Section 13, cost recovery for expenses incurred for the repair of G3SEI leaks shall be allowable through the GSEP. In accordance with G.L. c. 164, §§ 145 (a), (d), (e), the annual GSEAF associated with each GSEP Investment Year beginning on and after January 1, 2017, shall be effective on May 1 of the respective GSEP Investment Year, based on the GSEP Revenue Requirement calculated in the annual GSEP Plan filed with the Department on October 31 in the year prior to the GSEP Investment Year. The annual GSERAF shall be effective on the November 1 following each GSEP Investment Year.

Limitations on Annual GSEAF and GSERAF Charges:

Unless modified by the Department, annual changes in the GSEP recovery that may be billed in any year shall be limited by a cap ("GSEP Cap"), which is an amount equal to 3 percent of the Company's annual total firm revenues, including gas revenues attributable to sales customers and including imputed cost of gas revenues for transportation customers at the time of the October plan filing. G.L. c. 164, § 145 (f). For purposes of determining the GSEP Cap, total firm revenues will equal actual firm delivery revenues associated with the most recent calendar year plus average annual cost of gas revenues,which shall be calculated as (1) the average cost of gas per therm from 2013 through the most recent calendar year that actual data is available; and multiplied by (2) the average weather normalized sales and transportation volumes from 2013 through the most recent calendar year that actual data is available.

In addition, in the instance where the GSERAF is a surcharge to customers, the recovery of the annual GSERAF that may be billed in any year beginning in November 1 will be limited by the difference between the GSEP Cap and the annual change in the GSEP recovery.

In accordance with G.L. c. 164, § 145 (f), the Department may increase the GSEP Cap to a percentage of total firm revenues, including gas revenues attributable to sales customers and including imputed cost of gas revenues for the Company's transportation customers, greater than 1.5 percent. The Department has approved an increase to the Company's GSEP Cap percentage to 3 percent as defined above.

Application of the GSEP Cap shall not affect the calculation of GSEP recovery, including GSEP Revenue Requirement, in subsequent periods. However, any GSEP recovery approved by the Department in excess of the GSEP Cap may be deferred for recovery in the following year.

Consistent with St. 2016. c. 188, Section 13, the Company shall exclude Eligible G3SEI Expense from the operation of the GSEP Cap and shall add the annual Eligible G3SEI Expense to the GSEP Revenue Requirement determined to be recoverable pursuant to the GSEP Cap for purposes of calculating the GSEAFs.

In the event the Company incurs capital cost to replace Existing Infrastructure having a G3SEI leak, the Company shall include the replacement cost in the GSEP Revenue Requirement that is subject to the GSEP Cap. In the event the Company incurs capital cost to replace infrastructure having a G3SEI leak that does not constitute Existing Infrastructure, the resulting capital cost shall be excluded from Eligible GSEP Investment and the GSEP Revenue Requirement, and shall be eligible for recovery in the Company's next general rate case.

Overhead and Burdens Adjustments

For purposes of GSEP calculations, the actual overheads and burdens shall be reduced to the extent that actual operation and maintenance ("O&M") overheads and burdens in a given year including the Pension/PBOP Adjustment Factor ("PAF") are less than the amount included in base distribution rates as determined in the Company's last base distribution rate case and the PAF. Such reduction shall be the difference between the actual O&M overheads and burdens and PAF and the amount included in base distribution rates and PAF. In addition, the percentage of capitalized overheads and burdens assigned to GSEP projects shall be set equal to the ratio of GSEP to non-GSEP direct costs in any given year

6.10 Gas Business Enablement ("GBE") Program Costs

For the period before the GBE Program goes into service and is operational, the annual recovery shall be the sum of actual O&M expense incurred to implement the GBE Program and the capital costs incurred by the Company's affiliate, National Grid USA Service Company, Inc., and billed to the Company as rent expense, subject to the review and approval of the Department, which shall be included in the LDAC.

For the period after the GBE Program goes into service and is operational, the annual recovery shall be the sum of actual O&M expense incurred to operate the GBE Program and the capital costs incurred by the Company's affiliate, National Grid USA Service Company, Inc., and billed to the Company as rent expense, as may be amended from time to time, subject to the review and approval of the Department, which shall be included in the LDAC.

The annual Gas Business Enablement Factor ("GBEF") shall be effective on November 1 following each calendar year based on (1) for costs incurred prior to October 1, 2021, the difference between the calendar year's allowable GBE Program costs incurred and the allowance in base distribution rates approved in D.P.U 17-170; and (2) for cost incurred on and after October 1, 2021, the full calendar year's allowable GBE Program costs incurred, as included in the annual GBE Program cost recovery filing submitted to the Department at least 90 days prior to November 1 of each year. To the extent that actual savings resulting from the implementation of the GBE Program are identified, the

Company shall reduce the annual GBE Program expense reflected in the LDAC by the actual cost savings.

6.11 Earnings Sharing Mechanism Credits

The annual Earning Sharing amount to be credited to customers pursuant to the Company's Performance-Based Ratemaking Tariff, M.D.P.U. No. 93, as may be amended from time to time. All amounts related to Earnings Sharing Mechanism approved for credit through the LDAF shall be subject to full reconciliation and carrying charges and the Bank of America rate, and subject to investigation and approval by the Department.

6.12 Geothermal Energy Provision ("GEP")

The annual recovery of the Revenue Requirement associated with investment and O&M incurred associated with the implementation and operation of the Company's Geothermal District Energy Demonstration Program, subject to the review and approval of the Department, will be included in the LDAC. The revenue requirements related to cumulative GEP investments, net of GEP Participant Fees, include depreciation, property taxes, and return based on the pre-tax cost of capital.

6.13 Effective Date of Local Distribution Adjustment Factor

The date on which the annual Local Distribution Adjustment Factors ("LDAF") become effective will be the first day of the annual period designated by the Company. Unless otherwise required by the Department, the Company shall submit LDAF filings as outlined in Section 6.18 of this clause at least 90 days before they are to take effect, and Gas System Enhancement Adjustment Factor ("GSEAF") filings by October 31.

6.14 Definitions

As used herein, the terms set forth below are defined as follows:

(1) Accumulated Deferred Income Taxes are the net reduction in Federal income and State franchise taxes associated with the use of accelerated depreciation allowed for income tax purposes.

(2) Accumulated Reserve for Depreciation is the cumulative net credit balance arising from the provision for Depreciation Expense.

(3) Annual Period Reconciliation Date for the Company will be coincident to the next annual period LDAF filing, 90 days prior to the next annual period effective date or as directed by the Department.

(4) Attorney General Consultant Expenses ("AGCE") are all reasonable costs and expenses associated with the Attorney General's retention of a consultant to assist with a proceeding before the Department. After allowing the full parties to the proceeding to comment regarding the necessity or the desirability of the consultants services and absent a showing that the costs of such services are unnecessary or not responsible or proper, the Department shall approve the costs. The costs for a consultant shall not exceed $150,000 per proceeding, unless approved by the Department based upon exigent circumstances, including the complexity of the proceeding. Once the costs have been approved by the Department, these costs shall be recognized by the Department for all purposes as proper business expenses of the Company, and are recoverable through rates without further approval by the Department.

(5) Balancing Penalty Revenues are penalties charged to transportation customers and third party gas suppliers for over or under deliveries on the Company's gas system.

(6) Combined Tax Rate is the combined state and federal income tax rate.

(7) Deferred Tax Benefit is the unamortized portion of actual Environmental Response Costs for the Company multiplied by the effective statutory federal and state income tax rate and by the Company's tax adjusted Weighted Cost of Capital as defined in Section 6.13.

(8) Depreciation Expense is the return of the Company's investment in Rate Base at established depreciation rates as approved by the Department in the Company's most recent base distribution rate case.

(9) Distribution Revenue Allocator is derived from the most recent base distribution rate case as approved by the Department and shall be as follows by Rate Class Grouping:

Effective through September 30, 2021:

	Boston	Colonial	Combined Company
Residential	66.0%	74.0%	67.4%
Small C&I	6.4%	13.9%	7.8%
Medium C&I	6.8%	6.5%	6.7%
Large C&I	13.5%	5.6%	12.1%
Extra Large C&I	7.3%	0.0%	6.0%
Total	100.0%	100.0%	100.0%

Combined	
Residential	67.4%
Commercial & Industrial	32.6%
Total	100.0%

Effective October 1, 2021:

	Boston	Colonial	Combined Company
Residential	65.8%	74.7%	67.5%
Small C&I	6.2%	13.8%	7.6%
Medium C&I	6.5%	6.9%	6.6%
Large C&I	13.6%	4.6%	11.9%
Extra Large C&I	7.9%	0.0%	6.4%
Total	100.0%	100.0%	100.0%

Combined	
Residential	67.5%
Commercial & Industrial	32.5%
Total	100.0%

(10) Earning Sharings is customers' share of the Company's excess earnings that is to be credited to customers pursuant to the Company's Performanced-Based Ratemaking Tariff, M.D.P.U. No. 93, as may be amended from time to time ("PBR Tariff").

(11) Economic Benefit is the difference between the revenue from and the marginal cost determined to provide interruptible transportation.

(12) EE Incentive Costs are incentives earned by the Company and approved by the Department.

(13) EE Program Costs are Energy Efficiency program costs as approved by the Department.

(14) Eligible G3SEI Expense is the O&M expense incurred by the Company to repair G3SEI during the GSEP Investment Year.

(15) Eligible GSEP Investment is the cost of Eligible Infrastructure Replacement Projects planned for the current GSEP Investment Year, plus the cumulative actual and planned cost of Eligible Infrastructure Replacement Projects completed through the end of the year prior to the current GSEP Investment Year, as summarized in the annual GSEP Plan. Costs included in the GSEP Revenue Requirement associated with Eligible GSEP Investment are depreciation expense, property taxes, and the return on investment utilizing the after-tax rate of return approved by the Department in the Company's most recent base distribution rate case, adjusted to a pre-tax basis by using the current federal and state income tax rates applicable to the GSEP Investment Year. Project costs shall be Eligible GSEP Investment in the year completed and placed into service. Eligible GSEP Investment includes costs recorded in the following MDPU/FERC plant accounts

Account No. 367/367	Mains – Transmission
Account No. 367/376	Mains – Distribution
Account No. 380/380	Services – Distribution
Account No. 381/381	Meters – Distribution
Account No. 382/382	Meter Installations – Distribution
Account No. 383/383	House Regulators – Distribution

The costs booked to the above accounts shall be determined in accordance with the Company's application of the Uniform System of Accounts for Gas Companies, 220 C.M.R. § 50.00, Gas Plant Accounts, in use during the test year of its previous base rate case filed pursuant to G.L. c. 164, § 94.

(16) Eligible GSEP Savings are the cumulative reduction in operating and maintenance leak repair expense achieved with the replacement of leak-prone main. Eligible GSEP Savings shall be equal to the most recent three-year average of leak repair cost per mile for non-cathodically protected steel mains, cast iron mains, wrought iron mains and pre-1985 Aldyl-A mains, updated annually in the GSEP Plan filed on October 31 of each year for the subsequent construction year. The costs associated with leak repair expense shall be determined in accordance with the Uniform System of Accounts for Gas Companies, 220 C.M.R. § 50.00, Operations and Maintenance Expense Accounts, in use during the test year of its previous base distribution rate case filed pursuant to G.L. c. 164, § 94.

(17) Eligible GEP O&M Expense is the annual amount O&M expense incurred to implement and operate the Geothermal District Energy Demonstration Program less Geothermal District Energy Demonstration Program Participant Fees associated with O&M expense and billed to participants of the Geothermal District Energy Demonstration Program through the end of the prior GEP Investment Year. Such O&M expense includes costs incurred as a result of:

Conducting thermal conductivity tests
Purchasing, installing, and maintaining within the five year term of the GEP ground source heat pumps

Purchasing and installing water heaters
Air duct and radiator improvement or replacement
Energy efficiency improvements
Gas equipment removal and disposal
Incremental labor
GEP evaluation, measurement, and verification
Geothermal technical analysis and design
Customer research and recruitment

(18) Eligible Infrastructure Replacement Project is a project to replace or improve the Company's existing infrastructure that: (i) is made on or after January 1, 2015; (ii) is designed to improve public safety or infrastructure reliability; (iii) does not increase the Company's revenue by connecting an improvement for a principal purpose of serving new customers; (iv) reduces, or has the potential to reduce, lost and unaccounted for natural gas through a reduction in natural gas system leaks; and (v) is not included in the Company's current rate base as determined in the gas company's most recent base distribution rate case. [G.L. c. 164, § 145(a); St.2016, c. 188, § 13].

(19) Environmental Response Costs includes all costs of investigation, testing, remediation, litigation expenses, and other liabilities relating to manufactured gas plant sites, disposal sites, or other sites onto which material may have migrated, as a result of the operating or decommissioning of Massachusetts manufactured gas facilities for the Company.

(20) ERISA is the Employee Information Retirement Income Security Act of 1974, as amended from time to time.

(21) Existing Infrastructure is mains, services, meter sets, and other ancillary facilities composed of non-cathodically protected steel, cast iron, wrought iron, copper, and pre-1985 Aldyl-A. G.L. c. 164, § 145(c).

(22) Expenses and recoveries associated with insurance and third-party claims shall include fifty percent (50%) of the expenses incurred and fifty percent (50%) of any recoveries or other benefits received by the Company as a result of such claims.

(23) G3SEI shall mean Grade 3 gas leaks that have been determined to have a significant environmental impact, defined, consistent with 220 CMR 114.07, as a leak if during the initial identification or the most recent annual survey:

1. the highest barhole reading shows a gas-in-air reading of 50% or higher or
2. the area of 2,000 square feet or greater in which the Company has detected either
   (a) a positive reading on Flame Ionization Unit ("FIU"), which detects flammable gas concentrations, or
   (b) a positive Combustible Gas Indicator ("CGI"), which detects flammable gas-in-air concentrations, surrounded by an area of either negative FIU readings or CGI readings.

(24) GBEF is the Gas Business Enablement Factor that recovers the GBE Allowable Cost, approved by the Department, beginning November 1 following each calendar year.

(25) GBE Allowable Cost is (1) for costs incurred prior to October 1, 2021, the difference between the GBE Recoverable Cost and the annual allowance in base distribution rates for the recovery of GBE Program costs as approved in D.P.U. 17-170, and (2) for cost incurred on and after October 1, 2021, the calendar year's GBE Recoverable Cost. Through September 30, 2021, GBE Allowable Cost can be an amount to be recovered from or credited to customers.

(26) GBE Program is the Company's and its affiliated companies' multi-year initiative for the implementation of an operating platform to result in increased efficiencies and the effectiveness of providing gas distribution service to customers, as approved by the Department. This provision allows for the recovery of costs incurred by the Company in associated with the implementation and operation of the GBE Program, subject to the Department's review and approval.

(27) GBE Reconciliation is the difference between each year's GBE Allowable Cost to be recovered through the GBEF as approved by the Department and the billed revenue from the GBEF associated with the recovery of the GBE Allowable Cost. The GBE Reconciliation shall include interest on any balance, accrued at the prime rate as reported by Bank of America, beginning in the month recovery commences.

(28) GBE Recoverable Cost is the (1) actual annual O&M expense incurred to implement the GBE Program prior to its in-service date and becoming operational, and O&M expense incurred to operate the GBE Program after its in-service date and becoming operational, and (2) actual annual rent expense incurred by the Company associated with the actual capital cost of the GBE Program as incurred by the Company's affiliate National Grid USA Service Company, Inc.

(29) GBE Recovery Period is the period during which the respective GBEF is in effect and which shall be the 12-month period November 1 through October 31.

(30) GEPF is the Geothermal Energy Provision Factor that recovers the aggregate GEP Revenue Requirement approved by the Department for actual geothermal demonstration project investments made in each GEP Investment Year.

(31) GEP Investment Year is the calendar year during which the Company makes eligible Geothermal District Energy Demonstration Program investments and incurs Eligible GEP O&M Expense.

(32) GEP Participant shall mean a participant of the Company's Geothermal District Energy Demonstration Program. Those eligible to participate in the Geothermal District Energy Demonstration Program shall be existing customers of the Company and those who have decided to receive service from the Company but have not yet connected to the Company's distribution system, receiving or anticipated to receive gas service on any of the Company's tariff rate classes except the Extra-Large Commercial and Industrial and Gas Lighting rate classes. Upon becoming a Geothermal District Energy Demonstration Program Participant, the Company may discontinue gas service to the Geothermal District Energy Demonstration Program Participant's service location if the Geothermal District Energy Demonstration Program Participant is an existing customer based upon the Geothermal District Energy Demonstration Program Participant's geothermal service in the GEP. If gas service is discontinued, the Geothermal District Energy Demonstration Program Participant shall be responsible for the gas service through the date that gas service is discontinued.

(33) GEP Participant Contribution shall mean (1) the GEP Participant Fee and (2) the Geothermal Customer Charge. Geothermal District Energy Demonstration Program Participants will receive a separate bill from the Company for their GEP Participant Contributions. Geothermal District Energy Demonstration Program Participants will receive 1 Geothermal Customer Charge per geothermal service location.

(34) GEP Participant Fee shall be a monthly fee billed to Geothermal District Energy Demonstration Program Participants over a 60 month period assessed based on the number of ground source heat pumps installed at the GEP Participant location as follows:

	Monthly	Total
Residential (Rate R-1/R-3)	$60.00	$3,600.00
Residential Low-Income (Rate R-2/R-4)	$45.00	$2,700.00
Commercial & Industrial	$90.00	$5,400.00

Once customers have been billed the total indicated per ground source heat pump for their respective rate class, billing of the applicable GEP Participant Fee will end.

(35) GEP Reconciliation is the difference between the GEP Revenue Requirement approved by the Department for recovery through the GEPF and the billed revenue from the Geothermal Customer Charge and the GEPF associated with the same GEP Investment Year. The GEP Reconciliation shall include interest on any balance, accrued at the prime rate as reported by *Bank of America*.

(36) GEP Recovery Period is the period during which the respective GEPF is in effect and which shall be the 12-month period November 1 through October 31.

(37) GEP Revenue Requirement is the annual revenue requirement associated with cumulative Geothermal Plant Investments and Eligible GEP O&M Expense incurred in the prior GEP Investment Year. For the GEP Recovery Period after a GEP Investment Year in which there is Geothermal Plant Investments, the GEP Revenue Requirement related to Geothermal Plant Investments shall reflect the revenue requirement for the GEP Investment Year and the year subsequent to the GEP Investment Year.

(38) Geothermal Customer Charge shall be a monthly charge assessed to all Geothermal District Energy Demonstration Program Participants effective with the commencement of geothermal service to support customer service-related functions associated with geothermal service as follows:

	Monthly
Residential (Rate R-1/R-3)	$4.00
Residential Low-Income (Rate R-2/R-4)	$3.00
Commercial & Industrial	$4.00

(39) Geothermal Plant Investments shall be the actual investment for assets associated with the Geothermal Energy Provision recorded as plant in-service and approved by the Department through the end of the prior GEP Investment Year less GEP Participant Fees billed and associated with plant investment to participants of the Geothermal District Energy Demonstration Program through the end of the prior GEP Investment Year.

(40) Gross Plant Investments are the capitalized costs of GSEP plant investments including costs of removal recorded on the Company's books for Eligible Infrastructure Replacement Projects. Gross Plant Investment for a GSEP Investment Year shall be the cumulative actual and planned cost of Eligible Infrastructure Replacement Projects completed through the end of the year prior to the current GSEP Investment Year and the planned capitalized investment for the current GSEP Investment Year associated with the GSEP Plan filed with the Department on October 31 of the year prior to the GSEP Investment Year. Actual capitalized cost of GSEP Investments shall include allowance for funds used during construction and applicable overhead and burden costs subject to the test provided in Section 6.09.

For GSEP projects where Incidental Infrastructure constitutes up to 25 percent of the total project footage, the costs related to these projects will be considered eligible infrastructure for GSEP recovery. For GSEP projects where Incidental Infrastructure constitutes more than 25 percent and less than 50 percent of the total project footage, the Company must provide contemporaneous documentation demonstrating that the replacement or retirement of Incidental Infrastructure was operationally necessary or cost effective. For GSEP projects where Incidental Infrastructure constitutes 50 percent or more of the total project footage, the project will not be considered eligible infrastructure for GSEP recovery.

(41) GSEAF is the Gas System Enhancement Adjustment Factor that recovers the aggregate GSEP Revenue Requirement approved by the Department for actual and planned Eligible GSEP Investment made beginning January 1, 2017, and in annual periods January 1 through December 31 of each GSEP Investment Year, with the annual recovery period beginning May 1 of each GSEP Investment Year for the cumulative spending on planned or completed projects anticipated to be placed in service through the end of the GSEP Investment Year.

(42) GSERAF is the Gas System Enhancement Reconciliation Adjustment Factor that recovers the GSEP Reconciliation Adjustment. The GSERAF shall be effective November 1 following each GSEP Investment Year and shall be submitted to the Department 90 days before the LDAF effective date of November 1.

(43) GSEP Investment Year is the annual period beginning on January 1 and ending on December 31, during which the Company anticipates placing GSEP Eligible Infrastructure Replacement Projects in service.

(44) GSEP Offsets represent the reduced operating and maintenance expense associated with the elimination of natural gas leaks through Eligible Infrastructure Replacement Projects. GSEP Offsets are determined by multiplying Eligible GSEP Savings by the total miles of non-cathodically protected steel mains, cast iron mains, wrought iron mains, pre-1985 Aldyl-A mains, and Incidental Infrastructure replaced or abandoned by the Company in the period January 1 through December 31 of the respective GSEP Investment Year. For the purposes of calculating the GSEP Offsets, the Company shall identify, by material type, all miles of mains replaced or abandoned in connection with GSEP projects.

(45) GSEP Plan is the Company's plan to replace or improve existing distribution infrastructure in accordance with G.L. c. 164, § 145, as filed with the Department on October 31 of each year, including information pertaining to eligible infrastructure replacement undertaken to eliminate natural gas system leaks in the subsequent construction year and over a future timeline allowing for the removal of all leak-prone infrastructure on an accelerated basis. G.L. c. 164, § 145 (a), (c) and (d).

(46) GSEP Reconciliation Adjustment is the difference between the GSEP Revenue Requirement on cumulative Eligible GSEP Investment for a GSEP Investment Year and the billed revenue from the GSEAF associated with the same GSEP Investment Year. The GSEP Revenue Requirement, for this purpose, shall reflect actual cumulative Eligible GSEP Investment. The GSEP Reconciliation Adjustment shall include interest on any balance, accrued at the prime rate as reported by Bank of America. The GSEP Reconciliation Adjustment shall be recovered through the GSERAF.

(47) GSEP Revenue Requirement is the accumulated revenue requirements through December 31 of each GSEP Investment Year based on the Eligible GSEP Investment to be completed during the GSEP Investment Year and inclusive of the actual and planned Eligible GSEP Investment incurred through the end of the year prior to the current GSEP Investment Year. The revenue requirement for each GSEP Investment Year will be calculated on a monthly basis, and shall shall represent the sum of the revenue requirement for each of the twelve months of the respective year. The annual revenue

requirement on Eligible GSEP Investment for subsequent years will be calculated based upon average calendar year-end balances.

(48) Incidental Infrastructure is any connected facilities such as services, meters, regulators, or pre-existing pipe segments, including but not limited to, plastic and cathodically protected steel pipe segments, that must be installed, replaced, or retired to enable a GSEP replacement project to become operational or to manage the costs of the GSEP replacement project, and where such segments are not more than 50 percent of the total replacement project footage.

(49) Labor Allocator is derived from the most recent base distribution rate case as approved by the Department and shall be as follows by Rate Class Grouping:

Effective through September 30, 2021:

	Boston	Colonial
Residential	70.1%	78.8%
Small C&I	6.1%	13.3%
Medium C&I	6.7%	4.5%
Large C&I	11.1%	3.4%
Extra Large C&I	6.0%	0.0%
Total	100.0%	100.0%

Effective October 1, 2021:

Residential	71.7%
Small C&I	8.1%
Medium C&I	6.2%
Large C&I	9.3%
Extra Large C&I	4.7%
Total	100.0%

(50) Non Firm Transportation Credits are the benefits derived from non firm transportation services that are not included in base distribution rates. Ninety (90) percent of the Non Firm Transportation Credit will be credited to firm customers.

(51) Non-Growth Plant Investments are the non-revenue producing capital investments.

(52) Number of Days Lag is the number of days lag to calculate the working capital requirements for LDAC allowable expenses for the Company as approved by the Department.

(53) Pension Costs are all costs associated with the Company's Pension Plans as determined by ASC 715 each year, and as approved by the Department in the Company's most recent annual LDAC filing, excluding Energy Efficiency-related pension costs effective January 1, 2016.

(54) Pension Plan is a Qualified Pension Plan, as defined by ERISA, and non-qualified pension benefits earned by employees pursuant to the Qualified Pension Plan benefit formula that exceed the limitiations of the Qualified Pension Plan.

(55) Post Retirement Benefits Other Than Pensions are the costs associated with PBOP as determined by ASC 715 each year, and as approved by the Department in the Company's most recent annual LDAC filing, excluding Energy Efficiency-related PBOP costs effective January 1, 2016.

(56) Post Retirement Benefits Plan Other Than Pension Plan is a Qualified PBOP, as defined by ERISA.

(57) Pre-Paid/Unfunded Pension and PBOP Amount is the difference between: (1) the actual cash contributions to the Pension Plan and the PBOP Plan and (2) the expense amounts recognized in accordance with ASC 715. Prepaid amounts excludes unamortized non-cash balances in the prepaid accounts related to FAS 158 and unamortized merger-related fair value adjustments.

(58) Prior Year is the calendar year previous to the effective date of a proposed Pension and PBOP Adjustment Factor.

(59) Property Tax Rate is the Company's composite property tax rate determined in the Company's most recent general base distribution rate case calculated as the ratio of total annual property taxes paid to total taxable net plant in service in the test year.

(60) Rate Base is the investment value upon which the Company is permitted to earn its authorized rate of return.

(61) Rate Base Allocator is derived from the most recent base distribution rate case as approved by the Department and shall be as follows by Rate Class Grouping:

Effective through September 30, 2021:

	Boston	Colonial
Residential	56.3%	69.3%
Small C&I	6.7%	15.0%
Medium C&I	8.2%	8.2%
Large C&I	18.3%	7.5%
Extra Large C&I	10.5%	0.0%
Total	100.0%	100.0%

Effective October 1, 2021:

	Boston	Colonial
Residential	59.0%	69.2%
Small C&I	6.8%	16.3%
Medium C&I	7.4%	9.2%
Large C&I	16.8%	5.3%
Extra Large C&I	10.0%	0.0%
Total	100.0%	100.0%

(62) Rate Class Grouping is the grouping of similar rate classes to form the basis for the allocation of certain categories in the LDAC. The Rate Class Groupings are defined as: Residential, Small Commercial and Industrial (Rate G-41 and Rate G 51 series), Medium Commercial and Industrial (Rate G-42 and Rate G 52 series), Large Commercial and Industrial (Rate G-43 and Rate G 53 series), and Extra Large Commercial and Industrial (Rate G-44 and Rate G 54 series).

(63) Reconciliation Deferral is the difference between: (1) the total pension and PBOP expense based on the actuarial forecast of pension and PBOP expense approved by the Department in the Company's applicable LDAC filing; and (2) the total expense amounts booked by the Company in accordance with the requirements of ASC 715 for the same year.

(64) Residential Assistance Adjustment ("RAA") shall include the lost revenues associated with the Company's low income discount.

(65) Service Quality Penalty ("SQP") shall include any service quality penalty assessed to Boston Gas Company or the former Colonial Gas Company in accordance with a Department approved service quality plan.

(66) Weighted Cost of Capital is the weighted cost of capital as set in the Company's most recent base distribution rate case.

(67) Weighted Cost of Debt is the weighted cost of debt as set in the Company's most recent base distribution rate case.

(68) Weighted Cost of Equity is the weighted cost of equity as set in the Company's most recent base distribution rate case.

6.15 Local Distribution Adjustment Factor Formulae

The Annual LDAF shall be comprised of an annual Sector Specific Energy Efficiency Factor (EEF), an annual Sector Specific Energy Efficiency Working Capital Factor (EEWCF), a Low Income Energy Efficiency Factor (LIEEF), a Low Income Energy Efficiency Working Capital Factor (LIEEWCF), a Non-Firm Transportation Capacity Credit (NFTF), a Working Capital Factor for Non-Firm Transportation Capacity Credit and Attorney General Consultant Expenses (WCFNMU), a Balancing Penalty Credit Factor (BPCF), an Attorney General Consultant Expenses Factor (AGCEF), a Remediation Adjustment Factor (RAF), a Pension and Pension Benefits Other than Pensions Adjustment Factor (PAF), a credit for Service Quality Penalties (SQPF), a Residential Assistance Adjustment Factor (RAAF), an annual Gas System Enhancement Adjustment Factor (GSEAF), an annual Gas System Enhancement Reconciliation Adjustment Factor (GSERAF), Gas Business Enablement Factor (GBEF), an Earnings Sharing Mechanism Factor (ESMF), and a Geothermal Energy Provision Factor (GEPF), as in effect from time to time, calculated according to the following formulae:

LDAF Formula Applicable to Residential Rate Tariffs:

LDAFis = EEFr + EEWCFr + LIEEFr-c + LIEEWCFr-c + NFTFs + WCFNMUs + BPCFs + AGCEFs + RAFis+ PAFs + SQPFis + RAAFs + GSEAFis + GSERAFis + GBEFs + GEPFs + ESMFs

LDAF Formula Applicable to Commercial and Industrial Rate Tariffs:

LDAFis = EEFc + EEWCFc + LIEEFr-c + LIEEWCFr-c + NFTFs + WCFNMUs + BPCFs + AGCEFs + RAFs + PAFs + SQPFis + RAAFs + GSEAFis + GSERAFis + GBEFs + GEPFs + ESMFs

Where:

i Designates a separate factor for each division, Boston and the former Colonial.

s Designates a separate factor for each Rate Class Grouping.

r-c: Designates a separate factor for the residential and commercial sectors as part of the Company's EE programs.

Residential Energy Efficiency Factor (EEFr) Formulae:

$$EEFr = \frac{EEr}{A{:}TPvolr + A{:}Tpvolrb} + \frac{EERAr + EEINr}{A{:}TPvolr + A{:}Tpvolrb}$$

Where:

r:	The residential sector.
EEr:	Energy Efficiency programs designed to conserve load annually in the residential sector, including Energy Efficiency-related pension and post retirement benefits other than pension costs.
EERAr:	Residential EE Reconciliation Adjustment to be included for recovery in the subsequent EEFr - Account 175.22 balances, inclusive of the associated interest, as outlined in Section 6.16.
EEINr:	Energy Efficiency incentives for the residential sector.
A:Tpvolr:	Annual Throughput volumes for residential sector.
A:Tpvolrb:	Annual Throughput volumes for residential sector for Blackstone Gas Company.

Residential Energy Efficiency Working Capital Factor:

$$EEWCFr = \frac{\dfrac{(EEWCAr \times CC) - (EEWCAr \times CD)}{(1 - TR)} + (EEWCAr \times CD) + EEWCRr}{A{:}TPvolr}$$

And:

$$EEWCAr = (EEr) \times (DL \div 365)$$

And:

$$EEr = EEr \times (A{:}TPvolr \div A{:}TPvolr)$$

Where:

EEWCFr:	Working Capital allowed per billed annual throughput volumes associated with EE Charges allocated annually as defined in Section 6.17.
EEWCAr:	Charges allowable for working capital allocation as defined in Section 6.17.
EEWCRr:	Working Capital Reconciliation Adjustment associated with annual residential EE charges - Account 142.22 as outlined in Section 6.17.
EEr:	Energy Efficiency programs designed to conserve load annually in the residential sector, including Energy Efficiency-related pension and post retirement benefits other than pension costs effective.
CC:	Weighted Cost of Capital as defined in Section 6.14.
CD:	Weighted Cost of Debt as defined in Section 6.14.
TR:	Combined Tax Rate as defined in Section 6.14.

DL: Number of Days Lag from the purchase of gas from suppliers to the payment by customers.

A:TPvolr: Annual Throughput volumes for residential sector.

Commercial/Industrial Energy Efficiency Factor (EEFc) Formulae:

$$EEFc = \frac{EEc}{A{:}TPvolc + A{:}TPvolcb} + \frac{EERAc + EEINc}{A{:}TPvolc + A{:}TPvolcb}$$

Where:

c: The commercial/industrial sector.

EEc: Energy Efficiency programs designed to conserve load annually in the commercial/industrial sector, including Energy Efficiency-related pension and post retirement benefits other than pension costs.

EERAc: Commercial and Industrial EE Reconciliation Adjustment to be included for recovery in the subsequent EEFc- Account 175.26 balances, inclusive of the associated interest, as outlined in Section 6.16.

EEINc: Energy Efficiency incentives for the commercial/industrial sector.

A:TPvolc: Annual Throughput volumes for commercial/industrial sector.

A:TPvolcb: Annual Throughput volumes for commercial/industrial sector for Blackstone Gas Company.

Commercial/Industrial Energy Efficiency Working Capital Factor:

$$EEWCFc = \frac{\dfrac{(EEWCAc \times CC) - (EEWCAc \times CD)}{(1 - TR)} + (EEWCAc \times CD) + EEWCRc}{A{:}TPvolc}$$

And:

$$EEWCAc = (EEc) \times (DL \div 365)$$

And:

$$EEc = EEc \times (A{:}TPvolc \div A{:}TPvolc)$$

Where:

EEWCFc: Working Capital allowed per billed annual throughput volumes associated with EE Charges allocated annually as defined in Section 6.17.

EEWCAc: Charges allowable for working capital allocation as defined in Section 6.17.

EEWCRc: Working Capital Reconciliation Adjustment associated with annual Commercial and Industrial EE charges - Account 142.26 as outlined in Section 6.17.

EEc:	Energy Efficiency programs designed to conserve load annually in the commercial/industrial sector, including Energy Efficiency-related pensions and post retirement benefits other than pensions.
CC:	Weighted Cost of Capital as defined in Section 6.14.
CD:	Weighted Cost of Debt as defined in Section 6.14.
TR:	Combined Tax Rate as defined in Section 6.14.
DL:	Number of Days Lag from the purchase of gas from suppliers to the payment by customers.
A:TPvolc:	Annual Throughput volumes for commercial/industrial sector.

Low Income Energy Efficiency Factor (LIEEF) Formulae:

$$\text{LIEEFr-c} = \frac{(\text{LIEE}) \times \text{DRAr-c}}{\text{A:TPvolr-c} + \text{A:TPvolbr-c}} + \frac{(\text{LIEERA} + \text{LIEEIN}) \times \text{DRAr-c}}{\text{A:TPvolr-c} + \text{A:TPvolbr-c}}$$

Where:

LIEE:	Energy Efficiency programs designed to conserve load annually available to qualifying Low Income Residential Customers, including Energy Efficiency-related pension and post retirement benefits other than pension costs.
LIEERA:	LIEE Reconciliation Adjustment - Account 175.31 balance to be included for recovery in the subsequent LIEEF, inclusive of the associated interest, as outlined in Section 6.16.
LIEEIN:	Energy Efficiency incentives for the low income sector.
A:TPvol:	Annual forecasted throughput volumes inclusive of all sales and transportation throughput for each sector.
A:TPvolb:	Annual forecasted throughput volumes inclusive of all sales and transportation throughput for each sector for Blackstone Gas Company.
DRA	Distribution Revenue Allocator as defined in Section 6.14.
r-c:	Designates a separate factor for the residential and commercial sectors as part of the Company's EE programs.

Low Income Energy Efficiency Factor Working Capital (LIEEWCF) Formula:

$$\text{LIEEWCFr-c} = ((((\text{LIEEWCA} \times \text{CC}) - (\text{LIEEWCA} \times \text{CD})) \div (1 - \text{TR}) + (\text{LIEEWCA} \times \text{CD}) + \text{LIEEWCR}) \times \text{DRAr-c}) \div \text{A:TPvolr-c}$$

And:

$$\text{LIEEWCA} = (\text{LIEE}) \times (\text{DL} \div 365)$$

Where:

LIEE:	Energy Efficiency programs designed to conserve load annually available to qualifying Low Income Residential Customers, including Energy Efficiency-related pension and post retirement benefits other than pension costs.
LIEEWCF:	Working Capital allowed per billed annual throughput volumes associated with LIEE Charges allocated annually as defined in Section 6.17.
LIEEWCA:	Charges allowable for working capital allocation as defined in Section 6.17.
LIEEWCR:	Working Capital Reconciliation Adjustment associated with annual LIEE charges - Account 142.31 balance as outlined in Section 6.17.
A:TPvol:	Annual forecasted throughput volumes inclusive of all sales and transportation throughput for low income residential sector.
CC:	Weighted Cost of Capital as defined in Section 6.14.
CD:	Weighted Cost of Debt as defined in Section 6.14.
TR:	Combined Tax Rate as defined in Section 6.14.
DL:	Number of Days Lag from the purchase of gas from suppliers to the payment by customers.
DRA:	Distribution Revenue Allocator as defined in Section 6.14.
r-c:	Designates a separate factor for the residential and commercial sectors as part of the Company's EE programs.

Annual Non Firm Transportation Capacity Credit Factor (NFTF) Formula:

$$\text{NFTFs} = \frac{(\text{NFTs} + \text{RAnft}) \times \text{DRAs}}{\text{A:TPvols}}$$

Where:

NFT:	Non Firm Transportation Capacity Credit as defined in Section 6.14.
A:TPvol:	Annual forecasted throughput volumes inclusive of all sales and transportation throughput.
DRA:	Distribution Revenue Allocator as defined in Section 6.14.
s:	Designates a separate factor for each Rate Class Grouping.
RAnft:	Non firm Transportation Capacity Credit Reconciliation adjustment - Account 175.42 balance, inclusive of the associated Account 175.42 interest, as outlined in Section 6.16.

<u>Working Capital Factor for Non Firm Transportation Capacity Credit, and Attorney General Consultant Expenses, (WCFNMU Formulae):</u>

WCFNMUs = ((((WCANMU x CC) – (WCANMU x CD)) ÷ (1 – TR) + (WCANMU x CD)+WCRNMU) x DRAs) ÷ A:TPvols

And:

WCANMU = (NFT+AGCE) x (DL ÷ 365)

and:

NFT = NFT x (A:TPvol ÷ A:TPvol)

and:

AGCE = AGCE x (A:TPvol ÷ A:TPvol)

Where:

NFT:	Non Firm Transportation Capacity Credit as defined in Section 6.14.
AGCE:	Attorney General Consultant Expenses as defined in Section 6.14.
A:TPvol:	Annual forecasted throughput volumes inclusive of all sales and transportation throughput.
WCFNMU:	Per unit working capital allowable per billed annual throughput volume as defined in Section 6.17.WCANMU: Non-firm Transportation Capacity Credit and Attorney General Consultant Expenses allowable for working capital application as defined in Section 6.17.
WCRNMU:	Working Capital Reconciliation Adjustment associated with Non Firm Transportation Capacity Credit and Attorney General Consultant Expenses charges - Account 142.42 balance as outlined in Section 6.17.
CC:	Weighted Cost of Capital as defined in section 6.14.
CD:	Weighted Cost of Debt as defined in Section 6.14.
TR:	Combined Tax Rate as defined in Section 6.14.
DL:	Number of Days Lag from the purchase of gas from suppliers to the payment by customers.
DRA:	Distribution Revenue Allocator as defined in Section 6.14.
s:	Designates a separate factor for each Rate Class Grouping.

<u>Annual Balancing Penalty Credit Factor (BPCF) Formula:</u>

$$\text{BPCFs} = \frac{\text{BPR x DRAs}}{\text{A:TPvols}}$$

Where:

BPR: Balancing Penalty Revenues as defined in Section 6.14.

A:TPvol: Annual forecasted throughput volumes inclusive of all sales and transportation throughput.

DRA: Distribution Revenue Allocator as defined in Section 6.14.

s: Designates a separate factor for each Rate Class Grouping.

Attorney General Consultant Expenses (AGCEF) Formula:

$$AGCEFs = \frac{(AGCE + RA_{AGCE}) \times DRAs}{A{:}TPvols}$$

Where:

AGCE: Attorney General Consultant Expenses as defined in Section 6.14.

RA_{AGCE} Attorney General Consultant Expenses Reconciliation Adjustment – Account 175.86 balance, inclusive of the associated Account 175.86 interest, as outlined in Section 6.16.

A:TPvol: Annual forecasted throughput volumes inclusive of all sales and transportation throughput.

DRA: Distribution Revenue Allocator as defined in Section 6.14.

s: Designates a separate factor for each Rate Class Grouping.

Remediation Adjustment Factor (RAF) Formula:

$$RAFs = \frac{(\text{sum}(ERC \div 7) - DTB + ((IE - IR) \times .5) + Rrac) \times DRAs}{A{:}TPvols}$$

And:

$$DTB = UERC \times TR \times (CD + (CE \div (1 - TR)))$$

Where:

RAF: Remediation Adjustment Factor.

ERC: Environmental Response Costs as defined in Section 6.14.

UERC: Unamortized Environmental Response Costs.

DTB: Deferred tax benefit associated with Environmental Response Costs as defined in Section 6.14.

IE: Expenses associated with pursuit of insurance carriers and third-parties as defined in Section 6.14.

IR: Insurance carrier and third-party recoveries as defined in Section 6.14.

Rrac: Remediation Adjustment Clause Reconciliation Adjustment - Account 175.90 balance as outlined in Section 6.15.

A:TPvol: Annual forecasted billed throughput volumes inclusive of sales and transportation.

CE: Weighted Cost of Equity as defined in Section 6.14.

CD: Weighted Cost of Debt as defined in Section 6.14.

TR: Combined Tax Rate as defined in Section 6.14.

DRA: Distribution Revenue Allocator as defined in Section 6.14.

s: Designates a separate factor for each Rate Class Grouping.

Pension and Post-Retirement Benefits Other than Pensions Adjustment Factor (PAF) Formula:

$PAFs_x$ = $(((PEXP+PBOPEXP+RA_c+CC\ (URD_c+APPA_c - DTA_c) + PPRA_c) - MTB) \times LABs) \div A{:}TPvols$

Where:

PAF: The annual Pension/PBOP Adjustment Factor.

PEXP: The actuarial forecast of Pension Expense for the current year.

PBOPEXP: The actuarial forecast of PBOP Expense for the current year.

RA_c : The Reconciliation Adjustment for $Year_c$ shall equal one-third of each year's Reconciliation Deferral, as defined in Section 6.14 recorded during the prior three years.

CC: The Cost of Capital is the tax-effected weighted-average cost of capital as defined in Section 6.14.

URD_c : The Unamortized Reconciliation Deferral is the amount of the Reconciliation Deferral not yet included for recovery in the PAF. At the beginning of $Year_c$ the Unamortized Reconciliation Deferral is the sum of: (1) the Unamortized Reconciliation Deferral at the beginning of the Prior Year; plus (2) the Reconciliation Deferral for the Prior Year; minus (3) the Reconciliation Adjustment for the Prior Year.

$APPA_c$: The Average Pre-Paid/Unfunded Pension and PBOP Amount for $Year_c$ is one half of the sum of: (1) the Pre-Paid/Unfunded Pension and PBOP Amount recorded on the Company's books as of the beginning of the Prior Year; and (2) the Pre-Paid/Unfunded Pension and PBOP Amount recorded on the Company's books as of the end of the Prior Year.

DTA_c : The Deferred Tax Amount is the deferred taxes associated with the Pre-Paid/Unfunded Pension and PBOP Amount and the URD at the end of the Prior Year.

$PPRA_c$: Pension and PBOP Reconciliation Adjustment – Account 175.35 balance, inclusive of the associated Account 175.35 interest, as outlined in Section 6.16.

A:TPvol: Annual forecasted throughput volumes inclusive of all sales and transportation throughput.

c : The current year.

p : The prior year.

LAB: Labor Allocator as defined in Section 6.14.

s: Designates a separate factor for each Rate Class.

Annual Service Quality Penalty Factor (SQPF) Formula:

$$SQPFis = \frac{(SQPi + SQPRAi) \times DRAis}{A{:}TPvolis}$$

Where:

SQP: Service Quality Penalty as defined in Section 6.14.

i: Designates a separate factor for each division, Boston and the former Colonial.

A:TPvol: Annual forecasted throughput volumes inclusive of all sales and transportation throughput.

SQPRA: Annual Service Quality Penalty Reconciliation Adjustment - Account 175.38, inclusive of the associated interest, as outlined in Section 6.16.

DRA: Distribution Revenue Allocator as defined in Section 6.14.

s: Designates a separate factor for each Rate Class.

Residential Assistance Adjustment Factor (RAAF) Formula:

$$RAAFs = ((Cust \times Cust\$ \times Di\%) + (Cust \times AvgUse \times Use\$ \times D\%) + RAMP + (RA)) \times DRAs \div A{:}TPvols$$

Where:

RAAF: Residential Assistance Adjustment Factor for the forecasted period.

Cust: The projected number of customers for the forecasted period on the Company's Residential Assistance Rate (R-2 and R-4).

Cust$: The monthly customer charge for the rate classes.

D%: The applicable fixed discount percentage applied to the total billing calculated at the applicable rates of customers under the Company's low income tariffs (Rate R-2 and Rate R-4) set out in Section 6.08.

AvgUse: The projected therm usage per customer for the forecast period under the Company's Rate R-2 and Rate R-4.

Use$: The volumetric charges, including base rate volumetric charges, GAF, LDAF, and any other volumetric charges for the applicable rate classes.

RAMP: Incremental expense associated with the Arrearage Management Program, as approved by the Department.

RA: Residential Assistance Adjustment Clause Reconciliation Adjustment - Account 175.39 balance as outlined in Section 6.16.

A:TPvol: Annual forecasted billed through-put volumes inclusive of sales and transportation.

DRA: Distribution Revenue Allocator as defined in Section 6.14.

s: Designates a separate factor for each Rate Class.

<u>Gas System Enhancement Adjustment Factor (GSEAF) Formula</u>:

$CAPi = 3\% \times TOT\_REVi$

And:

$GSEP\_RECi_c = (RBi_{GSEP} \times PTRRi) + DEPRi_{GSEP} + PTMSi_{GSEP} - OFFi_{GSEP}$

And:

$RBi_{GSA} = ((GPi_{GSEPp} - ARDi_{GSEPp} + ADITi_{GSEPp}) + (GPi_{GSEPc} - ARDi_{GSEPc} + ADITi_{GSEPc})) \div 2$

If

$CAPi < (GSEP\_RECi_c - GSEAF\_RECi_{p)}$

Then

$$GSEAFis = \frac{(GSEP\_RECi_c - ((GSEP\_RECi_c - GSEAF\_RECi_p) - CAPi) + G3SEI) \times RBAis}{A:TPvolis}$$

Else

$$GSEAFis = \frac{((GSEP\_RECi_c + DEF\_RECi + G3SEI) \times RBAis}{A:TPvolis}$$

And

$DEF_RECi = $ Lesser of $(DEFi_r$ or $(CAPi - (GSEP\_RECi_c - GSEAF\_RECi_p)))$

Where:

GSEAFs: The Gas System Enhancement Adjustment Factor, by Rate Class Sector, as defined in Section 6.14.

i: Designates a separate factor for each division, Boston and the former Colonial.

s: Designates a separate factor for each Rate Class Grouping.

GSEP_REC: The GSEP Recovery, consisting of GSEP Revenue Requirement associated with the cumulative Eligible GSEP Investments for the respective GSEP Investment Year, excluding Eligible G3SEI Expense. Cumulative Eligible GSEP Investments will consist of actual and planned investment from January 1, 2017 through the end of the respective GSEP Investment.

$GSEAF\_REC_p$: The annual recovery amount reflected in the GSEAF for the applicable prior GSEP Investment Year excluding Eligible G3SEI Expense. The current year GSEP_REC is compared against the $GSEAF\_REC_p$ to quantify the change in the recovery that is to be compared to the CAP.

RBA: Rate Base Allocator as defined in Section 6.14.

A:TPvol: Forecasted Annual Throughput Volumes for each Rate Class grouping, inclusive of all firm sales and firm transportation throughput.

RB_{GSEP}: For the purpose of calculating the GSEAF, the average annual Rate Base associated with the cumulative Eligible GSEP Investments, based upon the beginning of the year and end of the year GP, ARD, and ADIT balances of the respective GSEP Investment Year. For the year in which Eligible GSEP Investment will be placed into service, Rate Base will be calculated using projected beginning and end of month balances for GP, ARD, and ADIT balances. For purposes of establishing the GSEP Reconciliation Adjustment for the year during which Eligible GSEP Investment is placed into service, Rate Base will be calculated using actual beginning and end of month balances for GP, ARD, and ADIT balances.

PTRR: The pre-tax rate of return shall be the after-tax weighted average cost of capital established by the Department in the Company's most recent base distribution rate case, adjusted to a pre-tax basis by using currently effective federal and state income tax rates applicable to the period of the Eligible GSEP Investment.

$DEPR_{GSEP}$: The annual depreciation expense associated with the cumulative Eligible GSEP Investments as of the end of the respective GSEP Investment Year. For purposes of determining the GSEAF, depreciation expense will be based on the average of the beginning and end of year plant balances. For the year in which Eligible GSEP Investment will be placed into service, depreciation expense will be calculated on a monthly basis based upon a monthly projection of GSEP Gross Plant Investment to be recorded as in-service. For purposes of determining the GSEP Reconciliation Adjustment for the year during which Eligible GSEP Investment is placed into service, depreciation expense will be calculated on a monthly basis based on the actual depreciation recognized on the monthly plant balances used in determining Rate Base.

$PTMS_{GSEP}$: The property taxes calculated based on the cumulative net GSEP plant investment at the end of the GSEP Investment Year multiplied by the Property Tax Rate established by the Department in the Company's most recent base distribution rate case. Property taxes will be included in the GSEP Revenue Requirement beginning in the year following the GSEP Investment Year at 50% of the annual property tax amount for the first year. In subsequent years, the GSEP Revenue Requirement will reflect a full year of property taxes.

OFF_{GSEP}: The total GSEP Offset associated with reduced leak repair operation and maintenance costs. The GSEP Offset for the first GSEP Investment Year will be 50% of the annual GSEP Offset calculated. In subsequent years, the GSEP Offset will reflect a full year of the calculated GSEP Offset. For purposes of determining the GSEP Reconciliation Adjustment for the first year of each GSEP Investment Year, the annual GSEP Offset will be allocated to months based upon the monthly miles of main replaced.

GP_{GSEP}: The cumulative GSEP Gross Plant Investments including cost of removal as of the end of the respective GSEP Investment Year. For the year in which Eligible GSEP Investment will be placed into service, GSEP Gross Plant Investments will be determined on a monthly basis based upon a monthly projection of GSEP Gross Plant Investment to be recorded as in-service. For purposes of determining the GSEP Reconciliation Adjustment for the year during which Eligible GSEP Investment is placed into service, GSEP Gross

	Plant Investments will be determined on a monthly basis based upon the month in which GSEP Gross Plant Investment was recorded as in-service.
ARD_{GSEP}:	The Accumulated Reserve for Depreciation associated with the cumulative Eligible GSEP Investments as of the end of the respective GSEP Investment Year. For the year in which Eligible GSEP Investment will be placed into service, the Accumulated Reserve for Depreciation will be determined on a monthly basis based upon the monthly projection of depreciation expense on GSEP Gross Plant Investment to be recorded as in-service. For purposes of determining the GSEP Reconciliation Adjustment for the year during which Eligible GSEP Investment is placed into service, the Accumulated Reserve for Depreciation will be determined on a monthly basis based upon actual depreciation expense on actual monthly GSEP Gross Plant Investment recorded as in-service.
$ADIT_{GSEP}$:	The Accumulated Deferred Income Taxes associated with the cumulative Eligible GSEP Investments as of the end of the respective GSEP Investment Year. For the year in which Eligible GSEP Investment will be placed into service, the Accumulated Deferred Income Taxes will be determined on a monthly basis based upon a monthly projection of GSEP Gross Plant Investment to be recorded as in-service. For purposes of determining the GSEP Reconciliation Adjustment for the year during which Eligible GSEP Investment is placed into service, the Accumulated Deferred Income Taxes will be determined on a monthly basis based upon the month in which actual GSEP Gross Plant Investment was recorded as in-service.
CAP:	The maximum change in the revenue requirement in any given year through the Company's GSEAF.
TOT_REV:	The total annual delivery and cost of gas revenues from sales and transportation throughput as defined in Section 6.09.
DEF:	Cumulative actual Reconciliation Adjustment amounts for the prior GSEP Investment Years which have not been reflected in rates due to being in excess of the CAP and are deferred for recovery in a subsequent GSEAF.
DEF_REC:	Amount of DEF that is allowed for recovery in the GSEAF.
G3SEI:	Eligible G3SEI Expense representing O&M costs incurred by the Company during the GSEP Investment Year to repair Grade 3 natural gas leaks determined to have significant environmental impact as defined in Section 6.14.
c:	The current year.
p.	The prior year.
r:	Subsequent GSERAF Filing.

<u>Gas System Enhancement Reconciliation Adjustment Factor ("GSERAF") Formula</u>:

If $(RAi - DEF\_RECi - GSERAF\_REVi_{May\text{-}Oct}) < 0$

Then

GSERAFis= $\dfrac{((RAi - DEF\_RECi - GSERAF\_REVi_{May\text{-}Oct}) + RA\_G3SEI) \times RBAis}{A: TPvolis}$

Else

If CAPi < $GSEP\_RECi_c - GSEAF\_RECi_p + DEF\_RECi$

Then

GSERAFi = $\dfrac{RA\_G3SEI \times RBAis}{A: TPvolis}$

Else

RA_RECi = Lesser of $(RAi -+ DEF\_RECi_f - GSERAF\_REVi_{May\text{-}Oct})$ or
$(CAPi - (GSEP\_RECi_c - GSEAF\_RECi_p + DEF\_RECi_f))$

And

$GSERAFi_s$= $\dfrac{(RA\_RECi + RA\_G3SEI) \times RBAis}{A: TPvolis}$

And

DEFi = $RAi - RA\_RECi - DEF\_RECi_f - GSERAF\_REVi_{May\text{-}Oct}$

Where:

s: Designates a separate factor for each Rate Class Sector.

i: Designates a separate factor for each division, Boston and the former Colonial.

$GSERAF_s$: The Gas System Enhancement Reconciliation Adjustment Factor, by Rate Class Sector, as defined in Section 6.14.

CAP: The maximum change in the revenue requirement in any given year through the Company's GSEAF.

GSEP_REC: The GSEP Recovery, consisting of GSEP Revenue Requirement associated with the cumulative Eligible GSEP Investments for the respective GSEP Investment Year. Cumulative Eligible GSEP Investments will consist of actual and planned investment from January 1, 2017 through the end of the respective GSEP Investment.

GSEAF_REC: The annual recovery amount reflected in the GSEAF for the applicable prior GSEP Investment Year. The current year GSEP_REC is compared against the $GSEAF\_REC_p$ to quantify the change in the recovery that is to be compared to the CAP.

RA:	GSEP Reconciliation Adjustment – Account 175.96, inclusive of the associated interest, as outlined in Section 6.16, for the GSEP Investment Years as of May 1 of each year.
RA_REC:	GSEP Reconciliation Adjustment that is allowed to be recovered in the GSERAF.
RBA_s:	Rate Base Allocator for each Rate Class Sector, as specified in Section 6.14.
$A{:}TPvol_s$:	Forecasted Annual Throughput Volumes for each Rate Class Sector, inclusive of all firm sales and firm transportation throughput.
c:	The current year.
p:	The pior year.
f:	Subsequent GSEAF filing.
DEF:	Cumulative actual Reconciliation Adjustment amounts for the prior GSEP Investment Years which have not been reflected in rates due to being in excess of the CAP and are deferred for recovery in a subsequent GSEAF.
DEF_REC:	Amount of DEF that is allowed for recovery in the GSEAF.
$GSERAF\_REV_{May\text{-}Oct}$:	GSERAF revenue estimated for the period May through October of the current year.
RA_G3SEI:	GSEP Reconciliation Adjustment for cost recovery of Grade 3 leaks determined to have significant environmental impact as defined in Section 6.14.

<u>Gas Business Enablement Factor (“GBEF”) Formula</u>:

$$GBEFs = \frac{(\,GBE\text{-}ALLOWp - GBE\text{-}SAVp + RA_{GBE}\,) \times DRAs}{A{:}TPvols}$$

Where:

GBEF:	The Gas Business Enablement Factor, as defined in Section 6.14.
p:	The prior year.
s:	Designates a separate factor for each Rate Class Grouping.
A:TPvol:	Forecasted Annual Throughput Volumes for each Rate Class grouping, inclusive of all firm sales and firm transportation throughput.
RA_{GBE}:	GBE Reconciliation Adjustment – Account 175.97 balance, inclusive of the associated Account 175.97 interest, as outlined in Section 6.16.
GBE-ALLOW:	The GBE Allowed Cost for the prior calendar year, as outlined in Section 6.14.
GBE-SAV:	The GBE Program direct costs savings identified.
DRA:	The Combined Distribution Revenue Allocator as defined in Section 6.14.

Earnings Sharing Mechanism Factor (ESMF) Formula:

$$ESMF_s = \frac{((ESM_P + RA_{PIESMY})) \times DRA_s}{A{:}TPvol_s}$$

Where:

s:	Designates a separate factor for each Rate Class Grouping.
p:	The prior year.
ESM:	Earning Sharing amount to be credited to customers as outlined in Section 6.14.
RA_{PIESMY}	Earning Sharing Mechanism Reconciliation Adjustment – Account 175.98 balance, inclusive of the associated Account 175.98 interest, as outlined in Section 6.16.
A:TPvol:	Annual forecasted throughput volumes inclusive of all sales and transportation throughput.
DRA:	Distribution Revenue Allocator as defined in Section 6.14.

Geothermal Energy Provision Factor ("GEPF") Formula:

$$GEPF_s = \frac{(\ GEP\_RR + RA\ ) \times DRA}{A{:}\ TPvols}$$

Where:

GEPF:	The Geothermal Energy Provision Factor, as defined in Section 6.14.
s:	Designates a separate factor for each Rate Class Grouping.
GEP_RR:	GEP Revenue Requirement as defined in Section 6.14.
RA:	GEP Reconciliation Adjustment – Account 175.99 balance, inclusive of the associated Account 175.99 interest, as outlined in Section 6.14.
DRA:	The Combined Distribution Revenue Allocator as defined in Section 6.14.
A: TPvols:	Forecasted Annual Throughput Volumes for each Rate Class grouping, inclusive of all firm sales and firm transportation throughput

6.16 Reconciliation Adjustments – Accounts 175

(1) The following definitions pertain to reconciliation adjustment calculations:

(a) Energy Efficiency Costs Allowable Per Annual Residential EE Formula shall be:

i. Charges associated with Residential EE programs designed to reduce annual load for each sector (EE), including Energy Efficiency-related pension and post retirement benefits other than pension costs, and including charges incurred by the Company as a result of providing EE services to residential customers of Blackstone Gas Company.

ii. Incentives associated with Residential EE programs (EEIN), including those earned by the Company as a result of providing EE services to residential customers of Blackstone Gas Company.
iii. Account 175.22 - Annual Residential EE interest charges.

(b) Energy Efficiency Costs Allowable Per Annual Commercial and Industrial EE Formula shall be:
i. Charges associated with C&I EE programs designed to reduce annual load for each sector (EE), including Energy Efficiency-related pension and post retirement benefits other than pension charges, and including charges incurred by the Company as a result of providing EE services to commercial and industrial customers of Blackstone Gas Company.
ii. Incentives associated with C&I EE programs (EEIN), including those earned by the Company of a result of providing EE services to commercial and industrial customers of Blackstone Gas Company.
iii. Account 175.26 – Annual C&I EE interest charges.

(c) Energy Efficiency Costs Allowable Per Annual Low Income EE Formula shall be:
i. Charges associated with Low Income EE programs designed to reduce annual load (LIEE), including Energy Efficiency-related pension and post retirement benefits other than pension costs, and including charges incurred by the Company as a result of providing EE services to low income customers of Blackstone Gas Company.
ii Incentives associated with Low Income EE programs (LIEEIN), including those earned by the Company as a result of providing EE services to low income customers of Blackstone Gas Company.
iii. Account 175.31 - Annual Low Income EE interest charges.

(d) Pension Adjustment Clause Expenses Allowable shall be:
i. Costs associated with the Company's Pension Plans, excluding Energy Efficiency-related pension costs.
ii. Costs associated with the Company's Post-Retirement Plan Other Than Pension Plans , but excluding Energy Efficiency-related post retirement benefits other than pension costs.
iii. Account 175.35 annual pension interest costs.

(e) Service Quality Penalties Allowable shall be:
i. Service Quality Penalties assessed in accordance with a Department-approved Service quality plan.
ii. Account 175.38 - Annual service quality penalty interest costs.

(f) Residential Assistance Adjustment costs Allowable shall be:
i. Low income discounted revenues resulting from application of a 25% discount to customers receiving service on the Company's Residential Assistance Rates (R-2 and R-4).
ii. Incremental costs associated with the Arrearage Management Program, as approved by the Department.
iii. Account 175.39 annual Residential Assistance interest costs.

(g) Non Firm Transportation Capacity Credits Allowable Per Annual Non Firm Transportation Formula shall be:
  i. Credits associated with Non Firm Transportation Capacity Credits not included in base rates.
  ii. Account 175.42 - Annual Non Firm Transportation Capacity Credit interest charges.

(h) Attorney General Consultant Expenses Allowable shall be:
  i. The cumulative difference between the recovery and actual amount of expenses associated with the Attorney General Consultant Expenses.
  ii. Account 175.86 - Annual Attorney General Consultant Expenses interest charges.

(i) Remediation Adjustment Clause Expenses Allowable shall be:
  i. One seventh of each calendar year's Environmental Response Costs (ERC) as defined in Section 6.14, less the deferred tax benefit (DTB) as defined in Section 6.14.
  ii. One-half of insurance and third-party expenses, less one-half of insurance and third-party recoveries.

(j) Gas System Enhancement Program Costs Allowable shall be:
  i. The approved revenue requirement associated with the Gas System Enhancement Program.
  ii. Account 175.96 annual GSEP interest costs.

(k) Gas Business Enablement Program Costs Allowable shall be:
  i. The approved GBE Allowable Cost associated with the Gas Business Enablement Program.
  ii. Account 175.97 annual GBE Program interest costs.

(l) Earnings Sharing Mechanism Amount Allowable shall be:
  i. The approved Earnings Sharing amount associated with the ESM of the PBR Plan as outlined in Section 6.11.
  ii. Account 175.98 annual ESM interest costs.

(m) Geothermal Energy Provision Costs Allowable shall be:
  i. The approved GEP Allowable Cost associated with the Geothermal District Energy Demonstration Program.
  ii. Account 175.99 annual GEP interest costs.

(2) Calculation of the Reconciliation Adjustments

Account 175 contains the accumulated difference between annual costs and revenues for residential EE (Account 175.22), annual commercial and industrial EE (Account 175.26), annual Low Income EE (175.31), including EE revenues remitted by Blackstone Gas Company as a result of the Company providing EE services to customers of Blackstone Gas Company, Pension and PBOP (175.35), annual Service Quality Penalties (175.38), Residential Assistance Costs (175.39), Non Firm Transportation Capacity Credits (175.42), annual Attorney General Consultant Expenses (Account 175.86), Remediation Adjustment clause (Account 175.90), annual Gas System Enhancement Reconciliation (Account 175.96), annual Gas Business

Enablement Reconciliation (Account 175.97), Earnings Sharing amounts (Account 175.98) and annual Geothermal Energy Provision Reconciliation (Account 175.99).

Account 175.22 shall contain the accumulated difference between revenues toward residential EE costs as calculated by multiplying the annual residential EE factor times monthly residential throughput volumes.

Account 175.26 shall contain the accumulated difference between revenues toward commercial and industrial EE costs as calculated by multiplying the annual commercial and industrial EE factor times monthly commercial and industrial throughput volumes each month.

Account 175.31 shall contain the accumulated difference between revenues toward Low Income EE costs as calculated by multiplying the annual Low Income EE factor times total monthly throughput volumes.

Account 175.35 shall be the cumulative difference between (1) the revenue toward the pension and PBOP costs approved to be recovered through the LDAC, calculated by multiplying the Pension and PBOP Adjustment Factor times monthly firm throughput volumes and (2) the same year's total Pension and PBOP expense amounts associated with the current year as approved for recovery through the LDAC, which includes the actuarial estimate of pension and PBOP expense determined in accordance with ASC 715 plus the carrying charges on the Unamortized Reconciliation Deferral and Average Pre-Paid/Unfunded Pension and PBOP Amount, net of Deferreed Tax, and excludes the Pension and PBOP Reconciliation Adjustment.

Account 175.38 shall contain the accumulated difference between revenues toward Service Quality Penalties as calculated by multiplying the annual Service Quality Penalty factor times monthly throughput volumes.

Account 175.39 shall contain the accumulated difference between revenues toward Residential Assistance Costs as calculated by multiplying the annual Residential Assistance Adjustment factor times monthly throughput volumes. The reconciliation shall also reflect as a credit the recovery of accounts receivable allowed to be recovered through the Company's distribution rates for hardship protected customer accounts having amounts due the Company at December 31, 2016 and March 31, 2020 that were older than 360 days past due.

Account 175.42 shall contain the accumulated difference between credits from non firm transportation capacity as calculated by multiplying the Non Firm Transportation Capacity Credit Factor times monthly firm throughput volumes and Non Firm Transportation Capacity Credits allowed.

Account 175.86 shall contain the accumulated difference between revenues toward Attorney General Consultant Expenses as calculated by multiplying the Attorney General Consultant Expenses factor times monthly firm throughput volumes and Attorney General Consultant Expenses allowed.

Account 175.90 shall contain the accumulated difference between revenues toward Environmental Response Costs as calculated by multiplying the RAF times monthly firm throughput volumes and Environmental Response Costs allowable per formula.

Account 175.96 shall contain the accumulated difference between revenues billed through the GSEAF for GSEP Recovery associated with a respective GSEP Investment Year, as calculated by multiplying the $GSEAF_s$ times the respective Rate Class Sector monthly firm sales and transportation throughput, plus the revenues billed through the GSERAF as calculated by multiplying the $GSERAF_s$ times the respective Rate Class Sector monthly firm sales and transportation throughput unless otherwise identified in the Company's billing records, and the revenue requirement associated with the actual Eligible GSEP Investment allowed, plus carrying charges calculated on the average monthly balance using the consensus prime rate as reported by Bank of America and then added to the end-of-month balance. Any deferral of GSEP Recovery as a result of the limitation of the amount allowed to be billed in any one year in accordance with the GSEP Cap, shall be reflected in the GSEP Reconciliation Adjustment Account with the monthly calculation of carrying charges as set out herein.

The GSEP Revenue Requirement will initially be based on planned spending for Eligible Infrastructure Replacement Projects for the GSEP Investment Year, plus cumulative actual and planned investment in eligible in-service plant through the end of the prior GSEP Investment Year. Upon Department approval of actual Eligible GSEP Investment, the Company shall adjust the GSEP Revenue Requirement of the applicable GSEP Investment Year.

The GSEP Reconciliation Adjustment as of the implementation date of base distribution rates established in a Company's next base distribution rate case, including any aspect of the GSEP Reconciliation Adjustment pertaining to the cumulative deferral of revenue requirement recovery due to application of the GSEP Cap in prior year(s), shall be included in developing the GSEAF established as of the effective date of the new base distribution rates. Upon the effective date of new base distribution rates, the GSEAF then in effect that is based upon an annual GSEP Revenue Requirement not reflecting any adjustment associated with such pending rate case, shall be reduced to reflect the removal of that portion of the annual GSEP Revenue Requirement on cumulative GSEP Investment approved for recovery in new base rates. Subsequent October 31 filings of GSEP Plans shall exclude cumulative GSEP Investment included in rate base in the Company's most recent distribution rate case. The recovery of GSEP Investment not included in a base distribution rate case shall continue through the GSEP until the GSEP Investment is included in rate base as part of a subsequent base distribution rate case. The filing of a base distribution rate case does not result in a Company not recovering eligible GSEP costs incurred prior to the date new base distribution rates go into effect.

Account 175.97 shall contain the accumulated difference between revenue billed through the GBEF during a GBE Recovery Period associated with the GBE Allowable Cost, as calculated by multiplying the $GBEF_s$ by the respective Rate Class Sector monthly firm sales and transportation throughput, unless otherwise identified in the Company's billing records, and the GBE Allowable Cost, plus carrying charges calculated on the average monthly balance using the consensus prime rate as reported by Bank of America, and then added to the end-of-month balance.

Account 175.98 shall contain the accumulated difference between revenue billed through the ESMF associated with the Earnings Sharing amount, as calculated by multiplying the ESMF by the respective Rate Class Sector monthly firm sales and transportation throughput, and the Earnings Sharing amount, plus carrying charges calculated on the average monthly balance using the consensus prime rate as reported by Bank of America, and then added to the end-of-month balance.

Account 175.99 shall contain the accumulated difference between revenue billed to Geothermal District Energy Demonstration Program Participants through the Geothermal Customer Charge, revenue billed through the GEPF during a GEP Recovery Period associated with the GEP Allowable Cost, as calculated by multiplying the GEPFs by the respective Rate Class Sector monthly firm sales and transportation throughput, unless otherwise identified in the Company's billing records, and the GEP Allowable Cost, plus carrying charges calculated on the average monthly balance using the consensus prime rate as reported by *Bank of America*, and then added to the end-of-month balance.

In accordance with Department Approved EE Guidelines, the residential EE Reconciliation Adjustment (EERAr - as defined in Section 6.15) shall be calculated every year and will be included for recovery in the subsequent residential LDAF calculation. This reconciliation will incorporate the residential EE account (175.22) balance at the end of the twelve month approval period.

In accordance with Department Approved EE Guidelines, the commercial and industrial EE Reconciliation Adjustment (EERAc - as defined in Section 6.15) shall be calculated every year and will be included for recovery in the subsequent commercial and industrial LDAF calculation. This reconciliation will incorporate the commercial and industrial EE account (175.26) balance at the end of the twelve month approval period.

In accordance with Department Approved EE Guidelines the LIEE Reconciliation Adjustment (LIEERA - as defined in Section 6.15) shall be calculated every year and will be included for recovery in the subsequent residential and commercial/industrial LDAF calculations. This reconciliation will incorporate the Low Income EE account (175.31) balance as the end of the twelve month approval period.

The Pension and PBOP Reconciliation Adjustment ($PPRA_x$ - as defined in Section 6.15) shall be determined for use in the annual LDAF calculations incorporating the Pension and PBOP account (175.35) balance as of the annual reconciliation date as designated by the Company.

The annual Service Quality Penalty Reconciliation Adjustment (SQPRA - as defined in Section 6.15) shall be determined for use in the annual LDAF calculations incorporating the Service Quality Penalty account (175.38) balance as of the annual reconciliation date as designated by the Company.

The Residential Assistance Reconciliation Adjustment (RA - as defined in Section 6.15) shall be determined for use in the annual LDAF calculations incorporating the Residential Assistance account (175.39) balance as of the annual reconciliation date as designated by the Company.

The Non Firm Transportation Capacity Credit Reconciliation Adjustment (RAnft - as defined in Section 6.15) shall be determined for use in the annual LDAF calculations incorporating the Non Firm Transportation Capacity Credit account (175.42) balance as of the annual reconciliation date as designated by the Company.

The Attorney General Consultant Expenses Reconciliation Adjustment (RA_{AGCE} - as defined in Section 6.15) shall be determined for use in the annual LDAF calculations incorporating the Attorney General Consultant Expenses account (175.86) balance as of the annual reconciliation date as designated by the Company.

A Remediation Adjustment Clause Reconciliation Adjustment (Rrac - as defined in Section 6.15) shall be determined for use in the RAC calculations incorporating the RAC account (175.9) balance as of the annual RAC reconciliation date.

(3) Calculation of the RAF

The RAF consists of one-seventh of the actual Environmental Response Costs incurred by the Company, in any calendar year for each year until fully amortized, less a deferred tax benefit, plus one-half of insurance and third-party expenses for the calendar year, less one-half of insurance and third party recoveries for the calendar year, plus the prior year's RAF reconciliation adjustment. This amount is then divided by the Company's respective forecast of total firm throughput volumes for the upcoming year.

The deferred tax benefit is calculated by (1) applying the combined state and federal tax rates to the Company's unamortized Environmental Response Costs to arrive at the deferred tax. (2) The deferred tax is then multiplied by the tax adjusted cost of capital, calculated by dividing the Weighted Cost of Equity by one minus the tax rate and adding it to the weighted cost of debt, to arrive at the deferred tax benefit.

6.17 Reconciliation Adjustments - Accounts 142 – Working Capital

(1) The following definitions pertain to reconciliation adjustment calculations:

(a) Working Capital Gas Costs Allowable Per Annual Residential EE Formula shall be:
- i. Charges associated with residential EE programs designed to reduce annual load (EE).
- ii. Account 142.22 interest charges.

(b) Working Capital Gas Costs Allowable Per Annual Commercial and Industrial EE Formula shall be:
- i. Charges associated with commercial and industrial EE programs designed to reduce annual load (EE).
- ii. Account 142.26 interest charges.

(c) Working Capital Gas Costs Allowable Per Annual Low Income EE Formula shall be:
- i. Charges associated with residential EE programs designed to reduce annual load (LIEE).
- ii. Account 142.31 interest charges.

(d) Working Capital Gas Costs Allowable Per Annual Non Firm Transportation Capacity Credit, and Attorney General Consultant Expenses Formula shall be:
- i. Credits associated with nonfirm transportation capacity credits included in base distribution rates.
- ii. Costs associated with the Attorney General Consultant Expenses.
- iii. Account 142.42 interest charges.

(2) The annual Attorney General Consultant Expenses, Non Firm Transportation Capacity Credit, Residential EE, Commercial and Industrial EE, and Low Income EE working capital requirements shall be calculated by applying the days lag divided by 365 days to the working capital costs allowable per each formula defined above.

(3) The Attorney General Consultant Expenses, Non Firm Transportation Capacity Credit, Residential EE, Commercial and Industrial EE, and Low Income EE working capital allowances shall each be calculated by applying the Company's weighted cost of capital to each working capital requirement (2) to calculate the respective returns on working capital. The interest portion of each working capital allowance is calculated by multiplying each working capital requirement (2) by the weighted cost of debt. This portion is tax deductible. The return on each working capital less the interest portion of each working capital is then divided by one minus the tax rate. This figure plus the interest calculated above equals the working capital allowance for each.

(4) <u>Calculation of the Reconciliation Adjustments</u>

Accounts 142.22, 142.26, 142.31, and 142.42 contain the accumulated difference between working capital allowance revenues and the actual monthly working capital allowance costs as calculated from actual monthly costs. Each Account 142 shall contain the accumulated difference between revenues toward the working capital allowance and the working capital allowance.

An annual Residential EE Working Capital Reconciliation Adjustment (EEWCRr - as defined in Section 6.15) shall be determined for use in the annual Residential EE factor calculations incorporating the annual Residential EE working capital account (142.22) balance as of the annual reconciliation date designated by the Company.

An annual Commercial and Industrial EE Working Capital Reconciliation Adjustment (EEWCRc - as defined in Section 6.15) shall be determined for use in the annual Commercial and Industrial EE factor calculations incorporating the annual Commercial and Industrial EE working capital account (142.26) balance as of the annual reconciliation date designated by the Company.

An annual LIEE Working Capital Reconciliation Adjustment (LIEEWCR - as defined in Section 6.15) shall be determined for use in the annual Residential EE factor calculations incorporating the annual Low Income EE working capital account (142.31) balance as of the annual reconciliation date designated by the Company.

An annual Non Firm Transportation Capacity Credit, and an Attorney General Consultant Expenses Working Capital Reconciliation adjustment (WCFNMU - as defined in Section 6.15) shall incorporate the Non Firm Transportation Capacity Credit, and Attorney General Consultant Expenses Working Capital Account (142.42) balance as of the annual reconciliation date designated by the Company.

6.18 Application of the LDAF to Bills

The Company will employ the LDAFs as follows:

For all customers, the annual rates to customers shall be calculated by adding the appropriate factors as defined in Section 6.15 – the annual Sector Specific Energy Efficiency Factor (EEF), an annual Sector Specific Energy Efficiency Working Capital Factor (EEWCF), a Low Income Energy Efficiency Factor (LIEEF), a Low Income Energy Efficiency Working Capital Factor (LIEEWCF), a Non Firm Transportation Capacity Credit (NFTF), a Balancing Penalty Credit Factor (BPCF), a Working Capital Factor for Non Firm Transportation Capacity Credit and Attorney General Consultant Expenses (WCFNMU), a Remediation Adjustment Factor (RAF), an Attorney General Consultant Expenses Factor (AGCEF), a credit for Service Quality Penalties (SQPF), a Pension and Pension Benefits Other than Pensions Adjustment Factor (PAF), a Residential Assistance Adjustment Factor (RAAF), a Gas System Enhancement Adjustment Factor (GSEAF), a Gas System Enhancement Reconciliation Adjustment Factor (GSERAF), a Gas Business Enablement Factor (GBEF), an Earning Sharing Mechanism Factor (ESMF), and a Geothermal Energy Provision Factor (GEPF),.

The annual LDAC factors ($/therm) for each sector shall be calculated to the nearest hundredth of a cent per unit and will be applied to each customer's monthly sales volumes.

6.19 Information Required to be Filed with the Department

Information pertaining to the LDAF shall be filed with the Department in accordance with the standardized forms approved by the Department. Required filings include a monthly report which shall be submitted to the Department on the twentieth of each month, and an annual LDAF filing which shall be submitted to the Department at least 90 days before the date on which a new LDAF is to be effective or as directed by the Department.

A GSEP Plan submitted on or before October 31 of any year shall include a timeline for removal of all leak-prone infrastructure on an accelerated basis specifying an annual replacement pace and program end date with a target end date of either: (a) not more than 20 years, or (b) a reasonable target end date considering the allowable recovery cap established pursuant to G.L. c. 164, § 145(f). In addition, in relation to Eligible GSEP Investment in the subsequent construction year, the plan shall also include, but not be limited to:

(a) A plan for the completion of eligible infrastructure replacement projects relating to mains, services, meter sets and other ancillary facilities composed of non-cathodically protected steel, cast iron, wrought iron, copper, and pre-1985 Aldyl-A prioritized to implement the federal gas distribution pipeline integrity management plan annually submitted to the Department and consistent with subpart P of 49 C.F.R. part 192;

(b) An anticipated timeline for the completion of each project;

(c) The estimated cost of each project;

(d) Rate change requests;

(e) A description of customer costs and benefits under the plan; and

(f) Any other information the Department considers necessary to evaluate the plan.

The GSEP Plan shall also include a description of the process the Company will follow during the upcoming GSEP Investment Year to identify and repair G3SEI leaks. To the extent available or reasonably estimated, the Company will reference the number of G3SEI leaks to be repaired and provide a general estimate of the costs associated with repairing such leaks.

After the filing of the initial GSEP Plan on October 31, 2014, at five-year intervals, the Company shall provide the Department with a summary of its replacement progress to date, a summary of work to be completed during the next five years, and any similar information the Department may require.

On or before May 1 of each year subsequent to a GSEP Investment Year, the Company shall file with the Department certain information to support its GSEP Reconciliation ("GREC"). The Company shall file final project documentation for projects and GSEP-eligible G3SEI leak repairs completed in the prior year to demonstrate: (a) substantial compliance with the GSEP Plan in effect for the respective GSEP Investment Year; and (b) that project costs were reasonably and prudently incurred. The Company shall also file the revenue requirement based on the actual costs submitted in this filing, which shall form the basis of the GSERAF to become effective on November 1.

No later than 90 days prior to November 1 of each year, the Company shall submit a cost recovery filing proposing GBEFs for the recovery of the GBE Allowed Cost for the prior calendar year, plus the GBE Reconciliation, including interest thereon, to take effect November 1. The Company shall also include in this filing capital project documentation for project segments placed into service during the prior calendar year and other documentation supporting actual, O&M expense incurred by the Company through National Grid USA Service Company, Inc., and charged to the Company as O&M expense. The Company shall also include in its annual filing the benefits of GBE Program investments to the Company's customers.

On or before July 1 of each year subsequent to the GEP Investment Year, the Company shall submit a cost recovery filing proposing GEPFs for recovery of the GEP Allowed Cost for the prior calendar year, plus the GEP Reconciliation, including interest thereon, to take effect November 1. The Company shall also include in this filing capital project documentation for projects recorded as in-service during the prior GEP Investment Year and other documentation supporting Eligible GEP O&M Expense incurred by the Company during the GEP Investment Year. The Company shall also report in its annual filing on progress and results of the Geothermal District Energy Demonstration Program, including progress against goals, construction progress, outreach and education efforts, data collected and analyzed, interim lessons learned, and financial performance against budget.

Additionally, the Company shall file with the Department a complete list by (sub)account of all local distribution costs claimed as recoverable through the LDAC over the previous year, as included in the annual reconciliation. This information shall be submitted with each annual LDAF filing, along with complete documentation of the reconciliation adjustment calculations.

6.20 Other Rules

(1) The Department may, where appropriate, on petition or on its own motion, grant an exception from the provisions of these regulations, 220 CMR 6.00, upon such terms that it may determine to be in the public interest.

(2) The Company may, at any time, file with the Department an amended LDAF. An amended LDAF filing must be submitted 7 business days before the first billing cycle of the month in which it is proposed to take effect.

(3) The Department may, at any time, require the Company to file an amended LDAF.

(4) The operation of the LDAC is subject to all powers of suspension and investigation vested in the Department by G.L. c. 164.

6.21 Customer Notification

The Company will notify customers in simple terms of changes to the LDAF, including the nature of the change and the manner in which the LDAF is applied to the bill. In the absence of a standard format, the Company will submit this notice for approval at the time of each LDAF filing. Upon approval by the Department, the Company must immediately distribute these notices to all of its customers either through direct mail or with its bills.

AMENDMENTS TO UNIFORM SYSTEM OF ACCOUNTS FOR GAS COMPANIES

175.22 Residential EE Reconciliation Adjustment for LDAC
This account shall be used to record the cumulative difference between residential EE revenues and residential EE costs. Entries to this account shall be determined as outlined in the Local Distribution Adjustment Clause, 220 C.M.R. 6.10.

175.26 Commercial and Industrial EE Reconciliation Adjustment for LDAC
This account shall be used to record the cumulative difference between commercial and industrial EE revenues and commercial and industrial EE costs. Entries to this account shall be determined as outlined in the Local Distribution Adjustment Clause, 220 C.M.R. 6.10.

175.31 Low Income EE Reconciliation Adjustment for LDAC
This account shall be used to record the cumulative difference between Low Income EE revenues and Low Income EE costs. Entries to this account shall be determined as outlined in the Local Distribution Adjustment Clause, 220 C.M.R. 6.10.

175.35 Pension/PBOP Cost Reconciliation Adjustment for LDAC
This account shall be used to record the cumulative difference between Pension/PBOP revenues and Pension/PBOP costs. Entries to this account shall be determined as outlined in the Local Distribution Adjustment Clause, 220 C.M.R. 6.10.

175.38 Service Quality Penalty Reconciliation Adjustment for LDAC
This account shall be used to record the cumulative difference between Service Quality Penalty refunds and annual penalties allowable. Entries to this account shall be determined as outlined in the Local Distribution Adjustment Clause, 220 C.M.R. 6.10.

175.39 Residential Assistance Adjustment for LDAC
This account shall be used to record the cumulative difference between Residential Assistance revenues and Residential Assistance costs. Entries to this account shall be determined as outlined in the Local Distribution Adjustment Clause, 220 C.M.R. 6.10.

175.42 Annual Non Firm Transportation Capacity Credit Reconciliation Adjustment for LDAC
This account shall be used to record the cumulative difference between annual Nonfirm Transportation Capacity Credit refunds and annual Nonfirm Transportation Capacity Credits allowable. Entries to this account shall be determined as outlined in the Local Distribution Adjustment Clause, 220 C.M.R. 6.10.

175.86 Attorney General Consultant Expenses Reconciliation Adjustment for LDAC
This account shall be used to record the cumulative difference between Attorney General Consultant Expenses revenues and Attorney General Consultant Expenses. Entries to this account shall be determined as outlined in the Local Distribution Adjustment Clause, 220 C.M.R. 6.10.

175.90 Remediation Adjustment Clause Reconciliation Adjustment for LDAC
This account shall be used to record the cumulative difference between RAC revenues and RAC costs. Entries to this account shall be determined as outlined in the Local Distribution Adjustment Clause, 220 C.M.R. 6.10.

175.96 Gas System Enhancement Program Adjustment for LDAC
This account shall be used to record the cumulative difference between revenues toward the Gas System Enhancement Program revenue requirement and Department allowed recoveries. Entries to this account shall be determined as outlined in the Local Distribution Adjustment Clause, 220 C.M.R. 6.10.

175.97 Gas Business Enablement Program Adjustment for LDAC
This account shall be used to record the cumulative difference between revenues toward the Gas Business Enablement Program revenue requirement and Department allowed recoveries. Entries to this account shall be determined as outlined in the Local Distribution Adjustment Clause, 220 C.M.R. 6.10.

175.98 Earnings Sharing Mechanism Adjustment for LDAC
This account shall be used to record the cumulative difference between Earnings Sharing Mechanism credits to customers and Earning Sharing amounts allowed to be reflected in the LDAF. Entries to this account shall be determined as outlined in the Local Distribution Adjustment Clause, 220 C.M.R. 6.10.

175.99 Geothermal Energy Provision Adjustment for LDAC
This account shall be used to record the cumulative difference between revenues toward the Geothermal Energy Provision revenue requirement and Department allowed recoveries. Entries to this account shall be determined as outlined in the Local Distribution Adjustment Clause, 220 C.M.R. 6.10.

142.22 Annual Residential EE Working Capital Reconciliation Adjustment for LDAC.
This account shall be used to record the cumulative difference between annual residential EE working capital allowance revenues and annual residential EE working capital allowance. Entries to this account shall be determined as outlined in the Local Distribution Adjustment Clause, 220 C.M.R. 6.10.

142.26 Annual Commercial and Industrial EE Working Capital Reconciliation Adjustment for LDAC
This account shall be used to record the cumulative difference between annual commercial and industrial EE working capital allowance revenues and annual commercial and industrial EE working capital allowance. Entries to this account shall be determined as outlined in the Local Distribution Adjustment Clause, 220 C.M.R. 6.10.

142.31 Annual LIEE Working Capital Reconciliation Adjustment for LDAC
This account shall be used to record the cumulative difference between annual Low Income EE working capital allowance revenues and annual Low Income EE working capital allowance. Entries to this account shall be determined as outlined in the Local Distribution Adjustment Clause, 220 C.M.R. 6.10.

142.42 Annual Non Firm Transportation Capacity Credit, and Attorney General Consultant Expenses Working Capital Reconciliation Adjustment for LDAC

This account shall be used to record the cumulative difference between annual Non Firm Transportation Capacity Credit, and Attorney General Consultant Expenses working capital allowance revenue and annual Non Firm Transportation Capacity Credit, and Attorney General Consultant Expenses working capital allowance. Entries to this account shall be determined as outlined in the Local Distribution Adjustment Clause, 220 C.M.R. 6.10.

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DISTRIBUTION SERVICE TERMS AND CONDITIONS

1.0 RATES AND TARIFFS

1.1 Boston Gas Company d/b/a National Grid (the "Company") furnishes its various services under rates and/or special contracts ("Schedule of Rates") promulgated in accordance with the provisions of G.L. c. 164 and the regulations and billing and termination procedures of the Massachusetts Department of Public Utilities ("MDPU"), all as may be in effect from time to time. Such Schedule of Rates, which includes these Terms and Conditions, is available for public inspection during normal business hours at the offices of the Company and at the offices of the MDPU except as otherwise provided by law or regulation.

1.2 The Schedule of Rates may be revised, amended, supplemented or supplanted in whole or in part from time to time according to the procedures provided in MDPU regulations. When effective, all such revisions, amendments, supplements or replacements will appropriately supersede the present Schedule of Rates. In case of conflict between these Terms and Conditions and any orders or regulations of the MDPU, said orders or regulations shall govern.

1.3 The Company shall apply these Terms and Conditions on a non-discriminatory and non-preferential basis to all persons, partnerships, corporations or others (hereinafter "Customers" or the "Customer") who obtain service (as defined in Section 3 herein) from the Company pursuant to the Schedule of Rates, except as these Terms and Conditions are explicitly modified in writing by a rate or special contract. The provisions of Section 24 of these Terms and Conditions will specifically apply to all entities designated by the Customer as set forth in Section 24.5, to supply Gas to a Designated Receipt point for the Customer's account (hereinafter the "Supplier"). The Customer may act as its own Supplier provided it meets the requirements set forth in Section 24.

1.4 No representative of the Company has the authority to modify orally any provision or rate contained in the Schedule of Rates or to bind the Company to any promise or representation contrary thereto. Any such modification to the Schedule of Rates or any such promise contrary thereto shall be in writing, duly executed by an authorized officer of the Company, subject in all cases to applicable statutes and to the regulations of the MDPU.

1.5 The Company will advise any new Customers as to the least expensive rate available for distribution services for which they are eligible. If the Company is notified by the Customer in writing of an elected change in the Customer's distribution service, the Company will again advise the Customer as to the least expensive rate available for the distribution service for which they are eligible. Responsibility for selecting the applicable rate is and remains the responsibility of the Customer, subject to the provisions of the Schedule of Rates. Unless specifically stated to the contrary, all rates are based upon the provision of distribution service to the Customer on an annual basis. The Customer may change from one rate to another no more than once in any twelve (12) month period, unless warranted by a demonstrated change in the Customer's annual load profile. Any change in rate classification will not be retroactive if the change is requested by the Customer.

1.6 The Company reserves the right to impose reasonable fees and charges pursuant to the various provisions of these Terms and Conditions. Said fees and charges shall be set forth at Appendix B to these Terms and Conditions as approved by the MDPU.

DISTRIBUTION SERVICE TERMS AND CONDITIONS

1.7 In the event that the Company incurs minimum bill, inventory, transition, take or pay surcharges, imbalance charges, or any other charges associated with the provision of distribution service to Customers, the Company may impose an additional charge on the Suppliers serving said Customers as approved by the MDPU.

DISTRIBUTION SERVICE TERMS AND CONDITIONS

2.0 DEFINITIONS

Adjusted Target Volume	The volume of Gas determined pursuant to Section (ATV) 12.3.
Aggregation Pool	One or more Customer accounts whose Gas Usage is served by the same Supplier and aggregated pursuant to Section 24.6 of these Terms and Conditions for operational purposes, including but not limited to nominating, scheduling, and balancing gas deliveries to Designated Receipt Point(s) within the associated Gas Service Area.
Annual Reassignment Date	Five (5) Business Days prior to November 1 of each year when the Company reassigns Capacity to Suppliers pursuant to Section 13.6 of these Terms and Conditions.
Assignment Date	Five (5) Business Days prior to the first Day of each month when the Company assigns Capacity to Suppliers pursuant to Section 13.4 of these Terms and Conditions.
Account Number	A unique number generated by the Company and printed on the Customer's bill that the Customer must furnish to the Supplier to enable the Supplier to obtain the Customer's Gas Usage information pursuant to Section 24.4, and to initiate or terminate Supplier Service as set forth in Section 24.5 of these Terms and Conditions.
Business Day	Monday through Friday excluding holidays recognized by the Company, which will be posted on the Company's Website on an annual basis. If any performance date referenced in these Terms and Conditions is not a Business Day, such performance shall be the next succeeding Business Day.
Btu	One British thermal unit (i.e., the amount of heat required to raise the temperature of one pound of water one degree Fahrenheit at sixty degrees (60˚) Fahrenheit). MMBtu is one million Btus.
Capacity	Pipeline Capacity, Underground Storage Withdrawal Capacity, Underground Storage Capacity, and Peaking Capacity as defined in these Terms and Conditions.
Capacity Allocators	The proportion of the Customer's Total Capacity Quantity that comprises Pipeline Capacity, Underground Storage Withdrawal Capacity, and Peaking Capacity.
Ccf	A volume of gas equal to one hundred cubic feet.

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City Gate	The interconnection between a Delivering Pipeline and the Company's distribution facilities.
Company	Boston Gas Company d/b/a National Grid.
Company Gas Allowance	The difference between the sum of all amounts of Gas received into the Company's distribution system and the sum of all amounts of Gas delivered from the Company's distribution system as calculated by the Company for the most recent twelve (12) month period ending July 31. Such difference shall include, but not be limited to, Gas consumed by the Company for its own purposes, line losses, and Gas vented and lost as a result of an event of Force Majeure, excluding gas otherwise accounted for.
Company-Managed Supplies	Capacity contracts held and managed by the Company in accordance with governing tariffs but made available to the Supplier pursuant to Section 13.9 of these Terms and Conditions, including supply-sharing contracts and load-management contracts.
Consumption Algorithm	A mathematical formula used to estimate a Customer's daily consumption.
Critical Day	In accordance with Section 19 of these Terms and Conditions, a Day declared at any time by the Company in its reasonable discretion when unusual operating conditions may jeopardize operation of the Company's distribution system.
Customer	The recipient of Default Service and/or Distribution Service whose Gas Usage is recorded by a meter or group of meters at a specific location and who is a Customer of record of the Company.
Daily Baseload	The Customer's average usage per day that is assumed to be unrelated to weather.
Daily Index	The mid-point of the range of prices for the respective New England Citygates as published by Gas Daily under the heading "Daily Price Survey, Midpoint, Citygates, Algonquin citygates" and "Daily Price Survey, Midpoint, Citygates, Tennessee/Zone 6 (delivered)" for the relevant Gas Day listed under "Flow date(s)." In the event that the Gas Daily index becomes unavailable, the Company shall apply its daily marginal cost of gas as the basis for this calculation until such time that MDPU approves a suitable replacement.

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Day or Gas Day	A period of twenty-four (24) consecutive hours beginning at 10:00 a.m., E.T., and ending at 10:00 a.m., E.T., the next calendar day, or other such hours used by the Delivering Pipeline.
Dekatherm	Ten Therms.
Default Service	Gas commodity service provided to a Customer who is not receiving Supplier Service, in accordance with Section 15 of these Terms and Conditions. The provision of Default Service shall be the responsibility of the Company and shall be provided to the Customer by the Company or its designated supplier pursuant to law or regulation.
Delivering Pipeline	The interstate pipeline company that transports and delivers Gas to the Designated Receipt Point.
Delivery Point	The interconnection between the Company's facilities and the Customer's facilities.
Design Winter	The forecasted Winter during which the Company's system experiences the highest aggregate Gas Usage.
Designated Receipt Point	For each Customer, the Company designated interconnection between a Delivering Pipeline and the Company's distribution facilities at which point, or such other point as the Company may designate from time to time for operational purposes, the Supplier will make deliveries of Gas for the Customer's account. If the Customer's Designated Receipt Point is Everett, Wellesley, Milton (Ponkapoag), Polaroid, Arlington, Revere, Lexington, Reading, Burlington, Medford, Waltham, Weston, Lynn, or Lynnfield, and Company's distribution system is capable of delivering to the Customer Gas received at the interconnection between Company's distribution system and the tailgate of Distrigas of Massachusetts Corporation's LNG facility located in Everett, Massachusetts ("DOMAC Tailgate"), then the Company shall designate the DOMAC Tailgate as an alternate Designated Receipt Point for the Customer, and the Supplier may deliver Gas for such Customer's account at the DOMAC Tailgate provided that volumes so delivered must be specifically nominated at the DOMAC Tailgate in lieu of one of the aforementioned points in accordance with Sections 11.0 and 12.0 of these Terms and Conditions. Gas so nominated shall be deemed delivered at such point for purposes of Sections 11.0 and 12.0. The Company reserves the right to amend this tariff to

DISTRIBUTION SERVICE TERMS AND CONDITIONS

	establish limitations on the aggregate amount of Gas delivered at the DOMAC Tailgate to the extent necessary to prevent the aggregate amount of such deliveries from exceeding the capability of the Company's distribution system.
Designated Representative	The designated representative of the Customer, who shall be authorized to act for, and conclusively bind, the Customer regarding Distribution Service in accordance with the provisions of Section 25 of these Terms and Conditions.
Distribution Service	The transportation and delivery by the Company of Customer-purchased Gas on any Gas Day from the Designated Receipt Point to the Customer's Delivery Point pursuant to these Terms and Conditions.
Electronic Data Interchange (EDI)	The computer to computer exchange of routine information in a standard format using established protocols. EDI transactions are used in retail access programs to switch Customers from one Supplier to another or to exchange Customers' history, usage, or billing data between a distribution utility and a Supplier.
Electronic Bulletin Board (EBB)	An internet website that allows both the Company and Suppliers to electronically post nominations and other transportation-related information.
Gas	Natural gas that is received by the Company from a Delivering Pipeline at the Designated Receipt Point and delivered by the Company to the Delivery Point for the Customer's account. In addition, the term shall include amounts of vaporized liquefied natural gas and/or propane-air vapor that are introduced by the Company into its system and made available to the Customer as the equivalent of natural gas that the Customer is otherwise entitled to have delivered by the Company.
Gas Service Area	An area within the Company's distribution system as defined in Section 4 of these Terms and Conditions, for the purposes of administering capacity assignments, nominations, balancing, imbalance trading, and Aggregation Pools.
Gas Usage	The actual quantity of Gas used by the Customer as measured by the Company's metering equipment at the Delivery Point.
Heating Factor	The Customer's estimated weather-sensitive usage per degree day.

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Interruptible Distribution Service	Transportation Service provided to the Customer by the Company that is subject to curtailment by the Company and/or the Customer in accordance with Section 17 of these Terms and Conditions.
Maximum Daily Peaking Quantity (MDPQ)	The portion of a Customer's TCQ identified and allocated as Peaking Capacity, such that the maximum daily amount of Gas that can be withdrawn from a Supplier's Peaking Service Account pursuant to Section 16 of these Terms and Conditions shall be equal to the sum of all Customers' MDPQs in a Supplier's Aggregation Pool.
MDPU	The Massachusetts Department of Public Utilities.
Month	A calendar month of Gas Days.
Monthly Index	The average of the Daily Indices for the relevant Month.
Nomination	The notice given by the Supplier to the Company that specifies an intent to deliver a quantity of Gas to the Designated Receipt Point(s) on behalf of a Customer, including the volume to be received, the Designated Receipt Point(s), the Delivering Pipeline, the delivering contract(s), the shipper, the service package identification, and other such non-confidential information as may be reasonably required by the Company.
Off-Peak Season	The consecutive months May through October.
Operational Flow Order	The Company's instructions to the Supplier to take such action as conditions require, including, but not limited to, diverting Gas to or from the Company's distribution system pursuant to Section 19 of these Terms and Conditions.
Peak Day	The forecasted Gas Day during which the Company's system experience the highest aggregate Gas Usage.
Peaking Capacity	Capacity normally used by the Company to provide Peaking Service.
Peak Season	The consecutive months November through April.
Peaking Service	A supplemental supply service provided by the Company to effectuate the assignment of pro-rata shares of the Company's Peaking Capacity.
Peaking Service Account	An account whose balance indicates the total volumes of Peaking Service resources available to a Supplier, where the

DISTRIBUTION SERVICE TERMS AND CONDITIONS

	maximum balance in the account shall equal the Peaking Supply assigned to the Supplier pursuant to these Terms and Conditions.
Peaking Service Rule Curve	A system of operational parameters associated with the use of the Company's Peaking Capacity including, but not limited to, indicators of the necessary levels of Peaking Supply that must be maintained in Suppliers' Peaking Service Accounts in order for the Company to meet system demands under Design Winter conditions. The Company will provide the Peaking Service Rule Curve electronically as identified in Section 23 of these Terms and Conditions prior to the start of each Winter.
Peaking Supply	The aggregate amount of peaking supply required to meet the Company's forecasted peaking-supply needs during a Design Winter.
Peaking Supply Allocator	An allocation factor that represents the proportion of a Customer's estimated Gas Usage during the Design Winter that is generally served with Peaking Service supplies.
Pipeline Capacity	Transportation capacity on interstate pipeline systems normally used for deliveries of Gas to the Company, exclusive of Underground Storage Withdrawal Capacity and Underground Storage Capacity.
Reference Period	A period of at least twelve (12) months for which a Customer's Gas Usage information is typically available to the Company.
Supplier	Any entity licensed by the MDPU to sell Gas to retail Customers in Massachusetts, that has met the Company's requirements set forth in these Terms and Conditions, and that has been designated by the Customer to supply Gas to a Designated Receipt Point for the Customer's account.
Supplier Service	The sale of Gas to a Customer by a Supplier.
Therm	An amount of Gas having a thermal content of 100,000 Btus.
Total Capacity Quantity	The total amount of Capacity assignable to a Supplier (TCQ) on behalf of a Customer.
Underground Storage Capacity	Contracts for capacity in off-system storage facilities used to accumulate and maintain gas inventories for redelivery to the Company's city gates.
Underground Storage	Capacity for the withdrawal of gas inventories

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Withdrawal Capacity	maintained in off-system storage facilities, as well as the transportation capacity used to deliver such gas to the Company's city gates.
Winter	The period November 1 through March 31.

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3.0 CHARACTER OF SERVICE

3.1 The service that the Company will supply to any Customer shall be limited to the character of service which is available at the location to which such service is proposed to be furnished.

3.2 The furnishing of service by the Company under the Schedule of Rates and in accordance with these Terms and Conditions and the rules and regulations of the MDPU, and acceptance by the Customer constitutes a contract between the Company and the Customer under these provisions.

3.3 The benefits and obligations of accepting service shall inure to and be binding upon the successors and assigns, survivors, and executors or administrators, as applicable, of the Customer.

3.4 All rates within the Schedule of Rates are predicated upon service to a Customer at a single Delivery Point and metering installation, except as otherwise specifically provided by a given rate schedules. Where service is supplied to a Customer at more than one Delivery Point or metering installation, each single Delivery Point or metering installation shall be considered to be a separate Customer for purposes of applying the Schedule of Rates, except when a Customer is served through multiple points of delivery or metering installations for the Company's own convenience.

3.5 The Company may refuse to supply service to loads of unusual characteristics which, in its sole reasonable judgment, might adversely affect the quality of service supplied to other Customers, the public safety or the safety, of the Company's personnel. In lieu of such refusal, the Company may require a Customer to install any necessary regulating and protective equipment in accordance with the requirements and specifications of the Company.

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4.0 GAS SERVICE AREAS AND DESIGNATED RECEIPT POINTS

4.1 Boston Gas Company shall have five (5) Gas service Areas. Gas Service Areas are defined for purposes of administering capacity assignments, nominations, balancing, imbalance trading, and Aggregation Pools pursuant to these Terms and Conditions. Each such Gas Service Area shall be defined to include the municipalities listed within each such Gas Service Area, as follows:

(1) Area 1: Algonquin Gas Service Area

Abington	Chelsea	Medford	Somerville
Acton*	Cohasset	Milton	South Boston
Bedford*	Concord	Natick	Waltham
Belmont*	Dorchester	Needham	Watertown*
Boston	East Boston	Newton	Wayland
Braintree	Everett*	Norwood	Wellesley
Brighton	Framingham	Quincy	West Roxbury
Brookline	Jamaica Plain	Rockland	Weston
Carlisle*	Lexington*	Roslindale	Weymouth
Charlestown	Lincoln	Roxbury	Whitman

(2) Area 2: Algonquin Gas Service Area serving the former Colonial Gas Company Service Territory

Barnstable	Dennis	Harwich	Sandwich
Bourne	Eastham	Mashpee	Wareham
Brewster	Falmouth	Orleans	Yarmouth
Chatham			

(3) Area 3: Tennessee Gas Service Area

Acton*	East Brookfield	Lynnfield	Spencer
Arlington	Everett*	Nahant	Stoneham
Ayer	Gloucester	North Brookfield	Sudbury
Bedford*	Groton	Oxford	Swampscott
Belmont*	Harvard	Peabody	Wakefield
Beverly	Lancaster	Reading	Warren
Boxboro	Leicester	Revere	Watertown*
Brookfield	Leominster	Rockport	Webster
Burlington	Lexington*	Salem	West Brookfield
Carlisle*	Littleton	Saugus	Winchester
Clinton	Lunenburg	Shirley	Winthrop
Danvers	Lynn	Southbridge	Woburn
Dudley			

* For towns served by more than one Delivering Pipeline, the Designated Receipt Point is Delivery Point-specific.

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(4) Area 4: Tennessee Gas Service Area serving the former Essex Gas Company Service Territory

Amesbury	Groveland	Merrimac	Salisbury Beach
Boxford	Hamilton	Newbury	Topsfield
Byfield	Haverhill	Newburyport	Wenham
Essex	Ipswich	Rowley	West Newbury
Georgetown	Manchester	Salisbury	

(5) Area 5: Tennessee Gas Service Area serving the former Colonial Gas Company Service Territory

Billerica	Dunstable	Pepperell	Westford
Chelmsford	Lowell	Tewksbury	Wilmington
Dracut	North Reading	Tyngsboro	

4.2 For each Aggregation Pool as set forth by Section 24.6, the Company will designate at least one specific interconnection between a Delivering Pipeline and the Company's distribution facilities, at which point, or such other point as the Company may designate from time to time, the Supplier will make deliveries for the Aggregation Pool. The interconnections that the Company may assign as the Customer's Designated Receipt Point for the Aggregation Pool as follows:

(1) Algonquin Gas Transmission Company

Meter Number	Meter Name	Meter Number	Meter Name
00021	Norwood	00070	Mansfield Street
00023	East Braintree	00074	Wellesley
00027	Everett	00080	Polaroid
00032	Waltham	00081	Potter Street
00052	Ponkapoag	00089	Medford
00057	Weston	00827	Weymouth
		00838	West Roxbury

(2) Algonquin Gas Transmission Company serving the former Colonial Gas Company Service Territory

Meter Number	Meter Name
00018	Bourne
00051	Sagamore
00813	Rochester

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(3) Tennessee Gas Pipeline

Meter Number	Meter Name	Meter Number	Meter Name
020108	Southbridge	020191	Spencer
020110	Clinton	020192	Lexington
020111	Leominster	020341	Burlington
020115	Arlington	020343	Lynnfield
020116	Revere	020389	Peabody
020117	Lynn	020611	Acton
020118	Beverly/Salem	020935	Danvers
020119	Gloucester	020949	Lunenburg
020136	Reading	021023	Oxford

(4) Tennessee Gas Pipeline serving the former Essex Gas Company Service Territory

Meter Number	Meter Name
020122	Haverhill
020138	Wenham
020323	Essex

(5) Tennessee Gas Pipeline serving the former Colonial Gas Company Service Territory

Meter Number	Meter Name
020139	Tewksbury
020532	Wilmington
020572	Dracut
020808	Camp Curtis

DISTRIBUTION SERVICE TERMS AND CONDITIONS

5.0 CUSTOMER REQUEST FOR SERVICE FROM COMPANY

5.1 Application for Distribution Service, Default Service, or any other service offered by the Company to a Customer will be received through any duly authorized representative or agent of the Company. By accepting Distribution Service from the Company pursuant to these Terms and Conditions, a Customer expressly consents to the Company, or anyone working on the Company's behalf, contacting the Customer regarding issues related to Distribution Service and billing and payment, by any method including telephone, autodialed and prerecorded/artificial voice calls, email, text, and/or letter. By contacting the Company, a Customer may opt-out of receiving non-emergency communications through certain methods.

5.2 Before any service from the Company may commence, the Customer must request such service. A Customer applying for Distribution Service must also arrange for gas commodity service with a Supplier pursuant to Section 24 of these Terms and Conditions. A Customer may act as its own Supplier provided it meets all of the Supplier requirements delineated in Section 24.

5.3 A non-residential Customer applying for service may be required to supply a security deposit in accordance with Section 14 of these Terms and Conditions. The Company reserves the right to refuse service to any non-residential applicant who has not paid a deposit as required by the Company.

5.4 The Company may accept oral application by a prospective Customer for residential service, except as noted below in Section 5.5. All applicants must be of legal age to contract for service with the Company, and the Company reserves the right to verify the identity of the Customer and the application information given by the proposed Customer, through commercially or publicly available means. The Company may require an application for non-residential service to be in writing and may provide for the application to be submitted via the Company's Website as in accordance with Section 23 of these Terms and Conditions. When a written application for non-residential service is required by the Company, such service shall not commence until the Company has received the Customer's completed application form, except that the Company may, at its option, provide service to the Customer for an interim period not to exceed ten (10) Business Days pending the receipt of the Customer's completed application. No agent or employee of the Company is authorized to modify or affect by oral promise, agreement, or representation the provisions of such written application.

5.5 In the event that an oral application for service is received by the Company from an applicant who is not currently a Customer of record of the Company for service at a location where service is disconnected for non-payment, the Company may request application to be made in writing to any agent or duly authorized representative as a precondition for service, unless otherwise ordered by the MDPU. The Company reserves the right to refuse service, at any location, to an applicant who is indebted to the Company for any service furnished to such applicant. However, the Company shall commence service if the applicant has agreed to a reasonable payment plan.

5.6 Upon receipt of an application from a prospective Customer setting forth the location of the premises to be served, the extent of the service to be required, and any other pertinent information requested by the Company, the Company will advise the Customer of the type and character of the service it will furnish, under the applicable tariff, and if required, the location of the

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Company's metering and related equipment. The Company will have sole reasonable discretion on the location of meters and other related equipment. Upon request, the Company will furnish detailed information describing the connections necessary between the Company's facilities and the Customer's premises and Customer and Company responsibilities for installation of facilities.

5.7 An application for service will not be approved until the Customer has delivered to the Company a fully completed request for service form and the Company has determined that an adequate flow of Gas can be delivered to the Customer's Delivery Point under normal operating conditions.

5.8 Whenever the estimated expenditures necessary to supply Gas to a Customer or to resume service to a Customer after a discontinuance of service for over twelve (12) months, for reasons other than the needs of the Company, shall be of such an amount that the income to be derived from gas service at the applicable rates will, in the opinion of the Company, be insufficient to warrant such expenditures, the Company may, in addition to the payments for Gas under the applicable rate schedules, require the Customer to pay the whole or a part of such expenditures, or make such other reasonable payments as the Company may deem necessary.

5.9 The Company reserves the right to reject any application for service if the amount or nature of the service applied for, or the distance of the premise to be served from existing, suitable gas distribution facilities, or the difficulty of access thereto is such that the estimated income from the service applied for is insufficient to yield a reasonable return to the Company, unless such application is accompanied by a cash payment or an undertaking satisfactory to the Company guaranteeing a stipulated revenue for a definite period of time, or both.

5.10 A Customer shall be and remain the Customer of record and shall be liable for service taken until such time as the Customer requests termination of service and a final meter reading is obtained by the Company. Such final meter reading shall not be unduly delayed by the Company. The bill rendered by the Company based on such final meter reading shall be payable upon receipt. In the event that the Customer of record fails to give notice of termination of service to the Company or hinders the Company's access to the meter, the Customer of record shall continue to be liable for service taken until the Company either disconnects the meter or a new Customer assumes responsibility for taking service at such service location. The Customer shall be liable for all costs incurred by the Company when the Customer prevents access to the Company's equipment.

5.11 In the absence of a duly constituted Customer of record, receipt of service shall constitute the recipient a Customer of the Company and shall bind such Customer to the provisions of the Schedule of Rates but shall not relieve such Customer from an obligation to execute an application for service.

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6.0 CUSTOMER INSTALLATION

6.1 The Customer shall furnish, maintain, and operate the facilities between the Delivery Point and the Customer's equipment, unless otherwise agreed upon in writing by the Company and the Customer.

6.2 The Company reserves the right to disconnect its service at any time without notice or to refuse to connect its service if, to its knowledge and in its judgment, the Customer's installation has become or is dangerous, defective or in violation of the Company's requirements.

6.3 The Company shall not be required to commence or continue service unless and until the Customer has complied with all requirements of any and all governmental authorities and the Company with reference to the use of Gas on the premises. All inspections, reports and approvals (where required), must be received in writing by the Company before service shall be commenced or reconnected.

6.4 The Customer assumes full responsibility for the proper use of Gas delivered by the Company and for the condition, suitability, and safety of any and all equipment on the Customer's premises, or owned or controlled by the Customer which is not the Company's property. The Customer shall indemnify and save harmless the Company from and against any and all claims, expenses, legal fees, losses, suits, awards, or judgments for injuries to or deaths of persons or damage of any kind, whether to property or otherwise, arising directly or indirectly by reason of: (i) the routine presence in or use of Gas from pipes owned or controlled by the Customer; or (ii) the failure of the Customer to perform any of its duties and obligations as set forth in the Schedule of Rates where such failure creates safety hazards; or (iii) the Customer's improper use of Gas or gas appliances. The Company shall be liable only for direct damages resulting from the Company's conduct of its business pursuant to this section to the extent set forth in Section 20.2.

6.5 The Customer shall notify the Company in writing before making any significant change in the Customer's gas equipment which would affect the Company's facilities required to serve the Customer. The Customer shall be liable for any damage to the Company's property caused by Customer's additional or changed installation if made without prior notification to the Company.

6.6 The Customer shall not install, own, or maintain gas piping across or in the public way or any recorded private way without the prior written consent of the Company in each case obtained.

6.7 The Customer shall furnish and maintain, at no cost to the Company, the necessary space, housing, fencing, barriers, and foundations for the protection of the equipment to be installed upon the Customer's premises, whether such equipment is furnished by the Customer or the Company. If the Customer refuses, the Company may, at its option, charge the Customer for furnishing and maintaining the necessary protection of the equipment. Such space, housing, fencing, barriers, and foundations shall be in conformity with applicable laws and regulations and subject to the Company's specifications and approval.

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7.0 COMPANY INSTALLATION

7.1 The Company shall own, operate, and maintain, at its expense, its gas distribution facilities to the Delivery Point.

7.2 Unless otherwise specified herein, the Company will furnish and install, at locations it designates, one or more meters for the purpose of measuring the Gas delivered.

7.3 Whenever the Company determines that an unauthorized use of Gas is being made on the premises of a Customer, the Company may make such changes in its meters, appliances, or other equipment on said premises or take such other corrective action as may be appropriate to insure the safety and security of the equipment and its installation under the circumstances. Any such changes shall be made at the Customer's expense. Nothing in this paragraph shall be deemed to constitute a waiver of any other rights of redress that may be available to the Company or to limit in any way any legal recourse that may be open to the Company.

7.4 Any properly identified employee of the Company shall have access to the premises of the Customer at all reasonable times for the purposes of reading meters, testing the Customer's load, inspecting the Customer's premises and equipment, or of repairing, removing, or exchanging any or all equipment belonging to the Company, and for the purpose of removing its property on the termination of any service agreement or the discontinuance of service.

7.5 The Company will notify the Customer whenever it obtains information indicating that Gas is being diverted from the Customer's service or that the meter has been tampered with. Unless there is a violation of the Massachusetts Sanitary Code 105 C.M.R. 410.354 for which the Customer is not responsible, the Customer will be held responsible to the Company for any theft, leakage, or waste of Gas which may occur beyond the point of the meter installation.

7.6 Where service under the Schedule of Rates is to be used for temporary purposes only, the Customer may be required to pay the cost of installation and removal of equipment required to render service in addition to payments for Gas Usage. Said costs of installation and removal may be required to be paid in advance of any construction by the Company. If, in the Company's sole reasonable judgment, any such installation presents unusual difficulties as to metering the service supplied, the Company may estimate consumption for purposes of applying the Schedule of Rates. Unless otherwise approved by the Company in writing, temporary service shall be defined as installations intended for removal within a period not to exceed twelve (12) months.

7.7 The Company shall not be required to install the equipment necessary to provide its service unless the Customer shall have obtained and provided to the Company at its request all certificates, permits (except street permits), and licenses from governmental authorities and such grants of rights-of-way as may be requisite to enable the Company to install and furnish the requested service. The subsequent termination of any certificate, permit, license, or right-of-way requisite for such service shall terminate any contract then existing for such service without any liability on the Company for breach of such contract or failure to furnish service.

7.8 The Company shall make, or cause to be made, application for any necessary street permits and shall not be required to supply service until a reasonable time after such permits are granted.

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7.9 All meters, services, and other gas equipment owned by the Company shall be and will remain the property of the Company, and no one other than an employee or authorized agent of the Company shall be permitted to remove, operate, or maintain such property. The Customer shall not interfere with or alter the meter, seals, or other property used in connection with the rendering of service or permit the same to be done by any person other than the authorized agents or employees of the Company. The Customer shall be responsible for all damage to, or loss of, such property unless occasioned by circumstances beyond the Customer's control. Such property shall be installed at points most convenient for the Company's access and service and in conformance with public regulations in force from time to time. The costs of relocating such property shall be borne by the Customer when done at the Customer's request, or for the Customer's convenience, or if necessary to remedy any violation of public law or regulation caused by the Customer.

7.10 Unless there is negligence on the part of the Company, the Company shall not be liable for damage to the person or property of the Customer or any other persons resulting from the use of Gas or the presence of the Company's appliances and equipment on the Customer's premises. In no event shall the Company be liable to any party for any indirect, consequential, or special damages, whether arising in tort, contract or otherwise, by reason of any services performed, or undertaken to be performed, or actions taken by the Company, or its agents or employees, under the Schedule of Rates or in accordance with or required by law.

7.11 The Company shall maintain the accuracy of all metering equipment installed pursuant hereto by regular testing and calibration in comparison to recognized standards. Any meter tested and found to register less than or equal to 2% above or below the recognized comparative standard shall be considered correct and accurate. A Customer may request the Company to test the accuracy of any of its metering equipment installed upon the Customer's premises. The Company may remove and test its meters at no charge to residential Customers. The Company may charge non-residential Customers for this testing if the meter tested is found to register less than or equal to 2% above or below the recognized comparative standard, and such test was conducted as part of an investigation into a high bill complaint by the Customer. Any such test shall be conducted according to the standards as established by this paragraph.

In the event that any meter fails to register or registers incorrectly, the Company shall reasonably determine the length of the period during which such meter failed to register or registered incorrectly and the quantity of Gas delivered during such period, based upon available information, including the Customer's records of Gas Usage and operation at the Customer's facility.

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8.0 QUALITY AND CONDITION OF GAS

8.1 Gas delivered to the Company by or for the Customer shall conform, in all respects, to the gas quality standards of the Delivering Pipeline. All Gas tendered by a Supplier at a Designated Receipt Point shall be of merchantable quality and shall be interchangeable with Gas purchased by the Company from its suppliers. The Company reserves the right to refuse non-conforming Gas.

8.2 In no event shall the Company be obligated to accept and deliver any Gas that does not meet the quality standards of the Delivering Pipeline.

8.3 The Company reserves the right to commingle Gas tendered by a Supplier at a Designated Receipt Point with other gas supplies, including liquefied natural gas and propane-air vapor.

8.4 Gas tendered by a Supplier at a Designated Receipt Point will be at a pressure sufficient to enter the Company's distribution system without requiring the Company to adjust its normal operating pressures to receive the Gas. The Company has no obligation to receive Gas at a pressure that exceeds the maximum allowable operating pressure of the Company's distribution system at the Designated Receipt Point.

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9.0 POSSESSION OF GAS

9.1 Gas shall be deemed to be in the control and possession of the Company after such Gas is delivered to the Designated Receipt Point and until the Gas is delivered to the Customer at the Delivery Point. The Company shall not be responsible for the Gas when the Gas is not in the Company's control and possession.

9.2 The Company shall not be liable to the Supplier or the Customer for any loss arising from or out of Distribution Service, including loss of Gas in the possession of the Company or for any other cause, except for the negligence of the Company's own employees or agents.

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10.0 COMPANY GAS ALLOWANCE

The amount of Gas tendered by the Supplier to the Designated Receipt Point will be reduced, upon delivery to the Customer's Delivery Point, by the respective Company Gas Allowance. Such adjustment will be included in each Company's Peak Season Cost of Gas Adjustment filing with the MDPU, and at the Company's option, will be posted on the Company's Website.

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11.0 DAILY METERED DISTRIBUTION SERVICE

11.1 Eligibility

All Customers (and their Suppliers) taking firm 365-day Distribution Service from the Company are eligible for Daily-Metered Distribution Service in accordance with Section 11 of these Terms and Conditions. Section 11 also applies to Customers taking Interruptible Distribution Service pursuant to Section 17.

11.2 Distribution Service Provided

This service provides transportation of Customer-purchased Gas from the Designated Receipt Point to the Delivery Point on any Gas Day for Customers electing to have Gas Usage recorded on a daily basis at the Delivery Point.

11.3 Nominations and Scheduling of Service

11.3.1 The Supplier is responsible for nominating and delivering on every Day an amount of Gas that equals the aggregated Gas Usage of Customers in the Aggregation Pool.

11.3.2 Nominations will be communicated to the Company by electronic means as determined by the Company pursuant to Section 23 of these Terms and Conditions, or, in the event of failure of such electronic means, by another alternative means including fax as specified in the Supplier's Service Agreement.

11.3.3 Nominations for the first Day of a Month shall be submitted to the Company no later than two (2) hours prior to the deadline for first of the Month nominations of the Delivering Pipeline or such lesser period as determined by the Company. The Company will make available, from time to time, a schedule of nomination due dates. Nominations on weekends, holidays, and non-business hours will be accepted by the Company on a best efforts basis.

11.3.4 The Supplier may make intra-Month nominations relating to changes to existing nominations for a given Month no later than two (2) hours prior to the deadline for intra-Month nominations of the Delivering Pipeline for the Gas Day on which the nomination is to be effective, or such lesser period as determined by the Company. Nominations on weekends, holidays, and non-business hours will be accepted by the Company on a best efforts basis.

11.3.5 The Supplier may make intra-Day nominations relating to changes to existing nominations within a given day no later than two (2) hours prior to the end of the Gas Day; provided, however, that the nomination must be in conformance with the requirements of and must be permitted by the Delivering Pipeline. Intra-Day nominations on weekends, holidays, and non-business hours will be accepted by the Company on a best efforts basis.

11.3.6 Nominations will be conditionally accepted by the Company pending confirmation by the Delivering Pipeline. The Company will attempt to confirm the nominated volume with the Delivering Pipeline. In the event of a discrepancy between the volume nominated to the Company by the Supplier and the volume nominated by the Supplier to the Delivering Pipeline,

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the lower volume will be deemed confirmed. In such situations, such discrepancy within the Supplier's Aggregation Pools within the same Gas Service Area will be allocated first to Supplier's Daily-Metered Aggregation Pool, and then to Supplier's Non-Daily Metered Aggregation Pool.

11.3.7 Nominations may not be accepted, at the sole reasonable discretion of the Company, if they do not satisfy the conditions for Distribution Service under the distribution tariffs in effect from time to time and these Terms and Conditions.

11.4 Determination of Receipts

11.4.1 The quantity of Gas deemed received by the Company for the Supplier's Aggregation Pool at the Designated Receipt Point(s) will equal the volume so scheduled by the Delivering Pipeline(s).

11.4.2 The respective Company Gas Allowance will be assessed against receipts pursuant to Section 10 of these Terms and Conditions.

11.5 Metering and Determination of Deliveries

11.5.1 For purposes of Daily Metered Distribution Service, the Company will provide equipment at the Customer's facility which will allow for daily wireless readings for the purpose of the measuring Gas Usage at each Customer's Delivery Point. The Company will install, own, and maintain the equipment in service and the Customer shall be responsible for the initial lump sum fee as identified in Appendix B. The Company will attempt to read the meters daily unless the delay is caused by the wireless service provider. This service requires a data plan from a telecommunications provider, which will be under the Company's name, with the Customer being responsible for the cost as identified in Appendix B. The Company will waive the initial lump sum fee if the Company requests an existing Daily Metered Customer who is currently being served with telemetering equipment to switch to a wireless service.

11.5.2 The Company will provide Daily Metered Distribution Service for new requests using wireless readings. At the Company's discretion in situations where wireless readings are not feasible due to technical or other logistical reasons, the Company shall furnish and install, at the Customer's expense, telemetering equipment and any related equipment for the purpose of measuring Gas Usage at each Customer's Delivery Point. The Company shall require each Customer to install and maintain, at the Customer's expense, reliably available telephone lines and electrical connections that meet the Company's operating requirements. Telemetering equipment shall remain the property of the Company at all times.

11.5.3 If there is a failure of the Company's equipment installed to provide Daily Metered Distribution Service, the Supplier will incur the normal imbalance charges except to the extent that the failure is caused by the Company, in which event the Company will waive any penalty imbalance charges for the billing period(s) during which the failure occurred. If there is an inactive telephone line, the Customer will have four (4) weeks to remedy the situation after notification by the Company to the Customer. In the event of an equipment malfunction, the previous Day's actual read will be deemed to be the Daily actual read until the situation is corrected. The Supplier in consultation with the Company will make a best effort attempt to have deliveries

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match customer usage during any period when the telemetering equipment is failing to properly record Customer use. If the malfunction was caused by the Customer and is not remedied within four (4) weeks the Customer will be returned to the applicable Default Service for a minimum of twelve (12) Months. The Company shall not be liable for any inaccuracies in the consumption reported due to malfunctioning equipment or telephone lines caused by the failure of the Customer to properly maintain such equipment or due to any other reason beyond the control of the Company. The Customer shall reimburse the Company for any unscheduled maintenance or repairs to the Company's equipment that is required to restore meter operation as a result of faulty telephone connection with respect to the operation of telemetering equipment or electrical connections or as a result of the actions of the Customer. However, the Company shall be responsible for restoring telephone or electrical connections that were caused as a result of its actions.

11.6 Balancing

11.6.1 The Supplier will maintain a balance between receipts at the Designated Receipt Point(s) and the aggregated Gas Usage of Customers in each Aggregation Pool. If the Delivering Pipeline posts notice on its electronic bulletin board that its customers will be required to adhere to a maximum hourly flow rate, the Supplier will be deemed to have notice that Maximum Hourly Flows will be in effect on the Company's distribution facilities as of the same time and for the same period as maximum hourly flows are in effect on the Delivering Pipeline. The Supplier's maximum hourly flow will be established based on an allocation of even hourly flows of daily receipts of gas scheduled in the relevant period in accordance with the applicable transportation tariff of the Delivering Pipeline. All Gas Usage in excess of the Suppliers maximum hourly flow rate will be subject to an unauthorized overrun penalty for each Dekatherm not delivered of 5 times the Daily Index. The Company will notify the Supplier of the Supplier's maximum hourly flow.

11.6.2 The Supplier must maintain a balance between daily receipts and daily usage within the following tolerances:

Off-Peak Season: The difference between the Supplier's aggregate actual receipts on the Delivering Pipeline to each Gas Service Area and the aggregated Gas Usage of Customers in the Aggregation Pool shall be within 15% of said receipts. The Supplier shall be charged a penalty of 0.1 times the Daily Index for all differences not within the 15% tolerance.

Peak Season: The difference between the Supplier's aggregate actual receipts on the Delivering Pipeline to each Gas Service Area and the aggregated Gas Usage of Customers in the Aggregation Pool shall be within 10% of said receipts. The Supplier shall be charged a penalty of 0.5 times the Daily Index for all differences not within the 10% tolerance.

Critical Day(s): The Company will determine if the Critical Day will be aggravated by an under-delivery or an over-delivery, and so notify the Supplier when a Critical Day is declared pursuant to Section 19 of these Terms and Conditions.

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Critical Day Aggravated by Under-delivery. The Supplier will be charged a penalty of 5 times the Daily Index for the aggregated Gas Usage of Customers in the Aggregation Pool that exceeds 102% of the Supplier's aggregate actual receipts on the Delivering Pipeline to the Gas Service Area. The Supplier will be charged a penalty of 0.1 times the Daily Index for the differences between said receipts and said usage that exceed 20% of said receipts [(Receipts - Usage) > (20% x Receipts)].

Critical Day Aggravated by Over-delivery. The Supplier will be charged a penalty of 0.1 times the Daily Index for the aggregated Gas Usage of Customers in the Aggregation Pool that exceeds 120% of the Supplier's aggregate actual receipts on the Delivering Pipeline to the Gas Service Area. The Supplier will be charged a penalty of 5 times the Daily Index for differences between said receipts and said usage that exceed 2% of said receipts [(Receipts - Usage > (2% x Receipts)].

In the event that the Delivering Pipeline requires its customers to balance on a point-specific basis, the Supplier must balance pursuant to this section at each Designated Receipt Point.

11.6.3 If the Supplier has an accumulated imbalance within a Month, the Supplier may nominate to reconcile such imbalance, subject to the Company's approval, which approval shall not be unreasonably withheld.

11.6.4 For each Aggregation Pool, the Supplier must maintain total Monthly receipts within a reasonable tolerance of total Monthly Gas Usage. Any differences between total Monthly receipts for an Aggregation Pool and the aggregated Gas Usage of Customers in the Aggregation Pool, expressed as a percentage of total Monthly receipts will be cashed out according to the following schedule:

Imbalance Tier	Over-deliveries	Under-deliveries
0% ≤ 5%	The average of the Daily Indices for the relevant Month.	The highest average of seven consecutive Daily Indices for the relevant Month.
> 5% ≤ 10%	0.85 times the above stated rate	1.15 times the above stated rate
> 10% ≤ 15%	0.60 times the above stated rate	1.4 times the above stated rate
> 15%	0.25 times the above stated rate.	1.75 times the above stated rate.

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For purposes of determining the tier at which an imbalance will be cashed out, the price will apply only to volumes within a tier. For example, if there is a 7% Under-delivery on a Delivering Pipeline, volumes that make up the first 5% of the imbalance are priced at the highest average of the seven consecutive Daily Indices. Volumes making up the remaining 2% of the imbalance are priced at 1.15 times the average of the seven consecutive Daily Indices.

11.6.5 In addition to the charges set forth in Section 11.6.2, the Company shall flow through to the Supplier any pipeline imbalance penalty charges attributable to the Supplier.

11.6.6 If, during any fifteen (15) consecutive Days, the Supplier delivers an amount less than 70% of the sum of the aggregated Gas Usage of Customers in the Aggregation Pool in said Days, the Company may declare the Supplier ineligible to nominate Gas for the following thirty (30) Days. The Supplier shall have the opportunity to cure the imbalance with the demonstration of verifiable imbalance trades or otherwise within twenty-four (24) hours of notification by the Company. If the Supplier is declared ineligible to nominate Gas for such 30 Days, the Supplier may be reinstated at the end of the 30 Days, provided it posts security equal to the product of: (1) the maximum aggregate daily Gas Usage of Customers in the Aggregation Pool expressed in MMBtu and (2) $300. If, within twelve (12) Months of the first offense, such Supplier is declared ineligible to nominate Gas pursuant to this section, the Supplier will be disqualified from service under these Terms and Conditions for one (1) full year from the time of the second disqualification. If the Supplier defaults on its obligations under these Terms and Conditions, the Company shall have the right to use such security to satisfy the Supplier's obligations. Such security may be used by the Company to secure Gas, transportation, storage, gathering, and to cover other related costs incurred as a result of the Supplier's default. The security may also be used to satisfy any outstanding claims that the Company may have against the Supplier, including imbalance charges, cash-out charges, pipeline penalty charges, and other charges.

11.6.7 If, as a result of the Company interrupting or curtailing service pursuant to Section 17 of these Terms and Conditions, the Supplier incurs a daily imbalance penalty due to over-delivery, the Company will waive such penalty for the first Day of the interruption or curtailment period. If the Company has issued notice of an interruption or curtailment in service and the Supplier is unable to change its nomination, or if the Supplier's Gas has been delivered to the Designated Receipt Point, then the Company will credit such Gas against the Supplier's imbalance.

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12.0 NON-DAILY METERED DISTRIBUTION SERVICE

12.1 Eligibility

All firm Customers (and their Suppliers) taking Distribution Service from the Company who have an annual load of less than 350,000 therms per year, except for those Customers taking Distribution Service under Rate Schedules G-43C, G-43E, G-53C, and G-53E, are eligible for Non-Daily Metered Distribution Service in accordance with Section 12 of these Terms and Conditions.

12.2 Distribution Service Provided

This service provides firm, 365-day transportation of Customer-purchased Gas from the Designated Receipt Point to the Delivery Point on any Gas Day for Customers, without the requirement for recording Gas Usage at the Delivery Point on a daily basis. Daily nominations are calculated by the Company on the basis of a consumption algorithm, and the Supplier is obligated to deliver to the Designated Receipt Point(s) such quantities. The Company shall make the consumption algorithm available to the Supplier upon request of the Supplier.

12.3 Nominations and Scheduling of Service

12.3.1 The Supplier is obligated to nominate and deliver the Adjusted Target Volume ("ATV"), as determined in Section 12.3.2, to the Designated Receipt Points on every Day for each Aggregation Pool.

12.3.2 The Company shall determine the ATV for each Aggregation Pool of Customers taking Non-Daily Metered Distribution Service for each Day using a consumption algorithm based on the degree day forecast for that Day. Information on the consumption algorithm shall be posted on the Company's Website as identified in Section 23. On each Business Day, the Company will communicate the forecasted ATV to the Supplier for the subsequent four (4) Days. The Company shall apply the ATV for a required Supplier nomination according to the following schedule:

(1) The ATV applied for a Day immediately following a Business Day will be communicated to the Supplier two (2) hours prior to the Company's nomination deadline for that Day as set forth in Sections 12.3.4 and 12.3.5.

(2) The ATV applied for a Day not immediately following a Business Day will be communicated to the Supplier two (2) hours prior to the Company's nomination deadline for the Day immediately following the last Business Day as set forth in Sections 12.3.4 and 12.3.5.

12.3.3 Nominations will be communicated to the Company by electronic means as determined by the Company pursuant to Section 23, or, in the event of failure of such electronic means, by another alternative means including fax as specified in the Supplier's Service Agreement.

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12.3.4 Nominations for the first Day of a Month shall be submitted to the Company no later than two (2) hours prior to the deadline for first of the Month nominations of the Delivering Pipeline or such lesser period as determined by the Company. The Company will make available, from time to time, a schedule of nomination due dates. Nominations on weekends, holidays, and non-business hours will be accepted by the Company on a best efforts basis.

12.3.5 The Supplier shall provide an intra-Month nomination no later than two (2) hours prior to the deadline of the Delivering Pipeline for the next Gas Day, or such lesser period as determined by the Company. Nominations on weekends, holidays, and non-business hours will be accepted by the Company on a best efforts basis.

12.3.6 Nominations will be conditionally accepted by the Company pending confirmation by the Delivering Pipeline. The Company will attempt to confirm the nominated volume with the Delivering Pipeline. In the event of a discrepancy between the volume nominated to the Company by the Supplier and the volume nominated by the Supplier to the Delivering Pipeline, the lower volume will be deemed confirmed. The Company will not confirm any volume nominated by the Supplier in excess of the ATV.

12.3.7 In the event that the Supplier is unable to deliver a confirmed ATV nomination, the Supplier may make intra-Day nominations relating to changes to existing nominations within a given day no later than two (2) hours prior to the end of the Gas Day provided, however, that the nomination must be in conformance with the requirements of and must be permitted by the Delivering Pipeline. Intra-Day nominations on weekends, holidays, and non-business hours will be accepted by the Company on a best efforts basis. The Company shall not adjust the ATV applied for that Day, unless in accordance with Section 19 of these Terms and Conditions.

12.3.8 Nominations may not be accepted, at the sole reasonable discretion of the Company, if they do not satisfy the conditions for Distribution Service under the transportation tariffs in effect from time to time and these Terms and Conditions.

12.3.9 All quantities of Gas over-delivered or under-delivered to the Company's system in violation of an OFO pursuant to Section 19 will be subject to the Critical Day provisions of Section 12.6.1 of these Terms and Conditions, and the delivered quantity specified in the OFO will replace the ATV.

12.4 <u>Determination of Receipts</u>

12.4.1 The quantity of Gas deemed received by the Company for the Supplier's Aggregation Pool at the Designated Receipt Point(s) will equal the volume so scheduled by the Delivering Pipeline(s).

12.4.2 The respective Company Gas Allowance will be assessed against receipts pursuant to Section 10 of these Terms and Conditions.

12.5 <u>Metering and the Determination of Deliveries</u>

The Company shall record the Customer's Gas Usage at the Delivery Point by making actual meter reads on a monthly or bi-monthly basis pursuant to Section 14 of these Terms and

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Conditions. In the event that the Customer's Gas Usage is metered on a bi-monthly basis, the Company shall make available to the Supplier estimates of the Customer's Gas Usage for each of the two billing months.

12.6 Balancing

12.6.1 Any difference between the Supplier's ATV for an Aggregation Pool and the receipts on the Delivering Pipeline to the appropriate Designated Receipt Point(s) will be cashed out by the Company according to the following:

Off-Peak Season: For receipts less than the ATV, the difference will be cashed out at 1.1 times the Daily Index. For receipts greater than the ATV, the difference will be cashed out at 0.8 times the Daily Index.

Peak Season: For receipts less than the ATV but greater than or equal to 95% of the ATV, the difference will be cashed out at 1.1 times the Daily Index. For receipts less than 95% of the ATV, the first 5% difference will be cashed out at 1.1 times the Daily Index, and the remaining difference will be cashed out at 2 times the Daily Index. For receipts greater than the ATV, the difference will be cashed out at 0.8 times the Daily Index.

Critical Day: The Company will determine if the Critical Day will be aggravated by an under-delivery or an over-delivery, and so notify the Supplier when a Critical Day is declared pursuant to Section 19.

Critical Day Aggravated by Under-delivery. For receipts less than the ATV, the difference will be cashed out at a penalty of 5 times the Daily Index. For receipts greater than the ATV but less than or equal to 125% of the ATV, the difference will be cashed out at the Daily Index. For receipts in excess of 125% of the ATV, the first 25% difference will be cashed out at the Daily Index, and the remaining difference will be cashed out at 0.8 times the Daily Index.

Critical Day Aggravated by Over-delivery. For receipts greater than the ATV, the difference will be cashed out at 0.4 times the Daily Index. For receipts less than the ATV but greater than or equal to 75% of the ATV, the difference will be cashed out at the Daily Index. For receipts less than 75% of the ATV, the first 25% difference will be cashed out at the Daily Index and the remaining difference will be cashed out at 1.1 times the Daily Index.

In the event that the Delivering Pipeline requires its customers to balance on a point-specific basis, the Supplier must balance pursuant to this section at each Designated Receipt Point.

12.6.2 In addition to the charges set forth in Section 12.6.1, the Company shall flow through to the Supplier any pipeline imbalance penalty charges attributable to the Supplier.

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12.6.3 If, during any fifteen (15) consecutive Days, the Supplier delivers an amount less than 70% of the sum of the ATVs of the Aggregation Pool in said Days, the Company may declare the Supplier ineligible to nominate Gas for the following thirty (30) Days. The Supplier shall have the opportunity to cure the imbalance with the demonstration of verifiable imbalance trades or otherwise within twenty-four (24) hours of notification by the Company. If the Supplier is declared ineligible to nominate gas for such 30 Days, the Supplier may be reinstated at the end of the 30 Days, provided it posts security equal to the product of: (1) the Supplier's estimated maximum aggregate daily Gas Usage of Customers in the Aggregation Pool expressed in MMBtu and (2) $300. If, within twelve (12) Months of the first offense, such Supplier is declared ineligible to nominate Gas pursuant to this section, the Supplier will be disqualified from service under these Terms and Conditions for one (1) full year from the time of the second disqualification. If the Supplier defaults on its obligations under these Terms and Conditions, the Company shall have the right to use such security to satisfy the Supplier's obligations. Such security may be used by the Company to secure Gas, transportation, storage, gathering and to cover other related costs incurred as a result of the Supplier's default. The security may also be used to satisfy any outstanding claims that the Company may have against the Supplier, including imbalance charges, cash-out charges, pipeline penalty charges, and other charges.

12.6.4 The Company shall use a daily cash out calculation to account for Company balancing requirements due to differences in forecast versus actual degree days. Using the consumption algorithm described in Section 12.3.2, the Company will recalculate the ATV for each Aggregation Pool for each day of the Month, substituting actual degree days for forecast degree days. Daily recalculations shall be compared to the Aggregation Pool's daily ATV, and the difference shall be cashed out at 100% of the Daily Index.

12.6.5 Each Month, the Company will compare the sum of the recalculated ATVs for each Aggregation Pool to the sum of the billed usage volumes used by each Aggregation Pool for that same period. The difference shall be cashed out at 100% of the weighted average Daily Index for the same period.

The Company shall allow Suppliers to trade Monthly differences. Prior to the Monthly cash-out, the Company shall make available a list of Suppliers. Aggregation Pools affected by the transaction must be located within the same Gas Service Area as defined in Section 4, unless waived by the Company. Suppliers who serve both Daily Metered and Non-Daily Metered Customers can not trade between Daily and Non-Daily Metered Aggregation Pools to offset imbalances. Trades can only be made that put Suppliers in a better imbalance position (i.e., trades between trading partners must bring each participant closer to a zero imbalance). All trades must be communicated to the Company within three (3) Business Days following receipt of the list.

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13.0 CAPACITY ASSIGNMENT

13.1 Applicability

Section 13 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 Sections 11 or 12, respectively, of these Terms and Conditions. Section 13 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 Assets for Assignment

13.2.1 Released Transportation Capacity

Five (5) Business Days before the end of each Month, the Company will provide the Capacity to be made available for assignment to Suppliers for the upcoming Month. Such reporting shall list, by Gas Service Area, all resource contracts eligible for assignment.

13.2.2 Released Storage and Associated Transportation Capacity

The Company shall assign certain storage capacity and associated transportation contracts to be billed to Supplier at maximum tariff rates or lesser rate paid by the Company.

13.2.3 Company Managed Supply

Capacity assigned by the Company may include Company-Managed Supplies, which includes; 7(c) Transportation and Storage contracts, downstream and/or upstream transportation contracts in the transportation path that includes any 7(c) contracts and Company Peaking assets that will be billed to the Supplier at maximum tariff rates or lesser rate paid by the Company.

13.2.4 Notification of Contract Changes to Company Capacity Portfolio

On or about September 1 of each year, the Company shall notify the Supplier of contract changes that would affect the Capacity portfolio resource allocation percentage or the associated Capacity cost. The Company will affirmatively notify all Suppliers serving Customers in the Company's service territory via electronic mail, facsimile, or telephone that such change has been posted. Such notification shall identify the contracts subject to 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.

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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 Boston Division Customers

For a Customer receiving only Distribution Service from Boston Gas Company on February 1, 1999, or who had a written request filed with Boston Gas Company on or before February 1, 1999 to receive only Distribution Service, the TCQ shall be zero where such Customer was not subject to the mandatory assignment of capacity under Boston Gas Company's transportation program in effect from December 1, 1996 through October 31, 2000. In the event that such Customer becomes a Default Service customer of the Company in the future, the TCQ shall be established pursuant to Section 13.3.2 of these Terms and Conditions.

For a Customer who was a Default Service customer on October 31, 1996, and converted to receiving only Distribution Service between December 1, 1996 and February 1, 1999, and therefore was subject to the mandatory assignment of capacity under Boston Gas Company's transportation program then in effect, the TCQ shall be equal to the total quantity of capacity assigned under that program, unless and until such Customer becomes a Default Service customer of the Company in the future. As of November 1, 2000, the Company may assign Capacity to such Customer consistent with the Capacity Allocators set forth in Appendix A, however, the total amount of capacity assigned to such Customer will remain unchanged. In the event that such Customer becomes a Default Service customer of the Company in the future, the TCQ shall be re-established pursuant to Section 13.3.2 of these Terms and Conditions.

Colonial Division Customers

For a Customer receiving only Distribution Service from the former Colonial Gas Company on February 1, 1999, or who had a written request filed with the former Colonial Gas 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.

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Essex Division Customers

For a Customer receiving only Distribution Service from the former Essex Gas Company on February 1, 1999, or who had a written request filed with the former Essex Gas 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 [Intentionally left blank]

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 taking Distribution Service under Rate Schedules G-43B,C,E and G-53B,C,E and Rate Schedules G-44B, and G-54B. 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 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.

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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 of these Terms and Conditions.

13.4 Capacity Assignments

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 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.

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 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.

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13.4.3 The Supplier shall accept, on behalf of any Customer taking Daily-Metered Distribution Service pursuant to Section 11 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.

13.5 Release of Contracts

13.5.1 With the exception of Company-Managed Supplies, pipeline capacity contracts shall be released by the Company to the Supplier, at the maximum tariff rate or 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.

13.5.2 Capacity contracts released to a Supplier on an Assignment Date shall be released through October 31 unless the contract expires earlier.

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 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).

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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 of these 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.

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 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 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

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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 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.

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.

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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 made 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 Underground Storage Capacity

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.

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 provide the Company's weighted average cost of inventories, by Gas Service Area, electronically 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

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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 provide the Company's weighted average cost of inventories, by Gas Service Area, electronically 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.

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, 7(c) Transportation and Storage contracts, downstream and/or upstream transportation contracts in the transportation path that includes any 7(c) contracts, and Company Peaking assets and other contracts that are not assignable to third-parties.

13.9.2 The Company shall provide the quantity of each Company-Managed Supply assigned to the Supplier pursuant to Sections 13.4 and 13.8 electronically each Month on or before the Assignment Date.

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 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

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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

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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.

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14.0 BILLING AND SECURITY DEPOSITS

14.1 The Customer shall be responsible for all charges for service furnished by the Company under the Company's applicable rates as filed from time to time with the MDPU, from the time service is commenced until it is terminated. The Company shall provide a single bill, reflecting unbundled charges, to Customers for Default Service.

14.2 The Company shall offer two billing service options to Customers taking Distribution Service: Standard Complete Billing Service and Standard Passthrough Billing Service. The Supplier shall inform the Company of the selected billing option in accordance with the provisions set forth in Section 24.5.

14.2.1 Standard Complete Billing Service

The Customer shall receive a single bill from the Company for both Distribution Service and Supplier Service. The Company shall use the rates supplied by the Supplier to calculate the Supplier's portion of the single bill, and integrate this billing within a single mailing to the Customer. The Company may charge a fee to the Supplier for providing this billing service as approved by the MDPU and as set forth in Appendix B.

The Company shall reasonably accommodate, at the Supplier's expense, different customer classes or rate structures as agreed to by the Company and the Supplier in the Supplier Service Agreement.

The Company shall provide an electronic file for the Supplier that will, in addition to the usage being billed, contain the calculated Supplier billing amounts for the current bill cycle. Customer revenue due the Supplier shall be transferred to the Supplier in accordance with the Supplier Service Agreement. Upon receipt of Customer payments, the Company shall provide a file for the Supplier summarizing all revenue from Supplier sales which have been received and recorded that day.

If a Customer pays the Company less than the full amount billed, the Company shall apply the payment first to Distribution Service, and if any payment remains, it shall be applied to Supplier Service.

14.2.2 Standard Passthrough Billing Service

The Customer taking Distribution Service shall receive two (2) bills: the Company shall issue one bill for Distribution Service; and the Supplier shall issue a second bill for Supplier Service.

The Supplier shall be responsible for the collection of amounts due to the Supplier from the Customer. Customer payment responsibility with Suppliers shall be governed by the particular Customer Supplier Contract.

Within three (3) Business Days following the end of the Customer's billing cycle, the Company shall provide an electronic file for the Supplier that will contain the Customer's usage being billed including the current and previous meter readings. The Company may charge a fee to the

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Supplier for providing the billing information described in this section as approved by the MDPU.

14.2.3 The Company shall print twelve (12) months' of historic usage data on the bill it issues to the Customer, in addition to the usage data for the current billing period.

14.2.4 Existing Company service fees, such as interest charges for unpaid balances and returned check charges, shall remain in effect and shall be assessed, as applicable, according to these Terms and Conditions.

14.3 The Company shall inform a Customer when Supplier Service has been initiated by a Supplier, along with information on how the Customer may file a complaint regarding an unauthorized initiation of Supplier Service. This information shall be included on the first bill rendered to the Customer after such initiation.

14.4 The Company shall schedule meter reads on a monthly or bimonthly cycle for billing purposes.

14.5 The term billing month as used in the Schedule of Rates shall refer to the time period between two (2) consecutive regular monthly meter readings (or estimates of such monthly meter readings), the latter of which occurs in the month to which reference is made, unless otherwise specifically stated within the Schedule of Rates. In the event that such time period is greater or less than thirty (30) days, billings will be appropriately adjusted by the Company.

14.6 The Company may, at its option, read meters and render bills on a bi-monthly basis to Customers in part or all of its service territory. When bills are rendered bi-monthly, the Company's Schedule of Rates will be applied in the following manner to compensate for such change:

(1) Monthly minimum charges, special equipment charges, demand charges, and other additive charges contained in Schedule of Rates shall be multiplied by two.

(2) Where consumption blocks are increased based on equipment rating or capacity, such increases shall be multiplied by two.

14.7 The Company may render an estimated bill in the event that a regular meter reading cannot be obtained as normally scheduled. At the Company's option, Customers whose meters are scheduled to be read bi-monthly may be billed in each intervening billing month on an estimated basis. Estimated bills shall be payable when rendered.

14.8 Any Customer who would otherwise receive an estimated bill as provided above may elect to receive a bill based on actual meter readings by reading its meter at the time prescribed by the Company, recording the meter reading accurately on an appropriate form (which will be furnished by the Company upon request of the Customer) and immediately submitting the meter reading to the Company, or by such other means as arranged by the Company.

14.9 The Customer shall be liable for all rates, charges, and surcharges allowed for in the Schedule of Rates related to services provided to each Customer individually.

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14.10 If the Company is unable to gain access to the Customer's premises to obtain actual meter reads for a non-residential account for more than three (3) billing months, the Company may install automatic meter reading devices, or relocate the meter to an outside location, at the Customer's expense. In the event that the Customer is receiving Supplier Service, the Company shall notify the Customer's Supplier of any change in the Customer's account number upon the change in meter device or location.

14.11 A Customer acting as its own Supplier will be subject to the billing and payment requirements in Section 24.8 of these Terms and Conditions.

14.12 Readings taken by an automated meter reading device will be considered actual readings for billing purposes.

14.13 Unless otherwise specified, bills of the Company are payable when rendered (received) and may be paid at the office of the Company or at any authorized collector or agency. Bills shall be deemed rendered and other notices duly given, when delivered to the Customer personally or three (3) days following the date of mailing to the premises supplied or to the last known address of the Customer, or when left at either of such places, or when electronically sent to Customers for Customers which have subscribed to electronic delivery of Company bills.

14.14 Bills rendered to residential Customers on a billing month basis for which payment has not been received within 45 days from the date rendered or a period of time greater than has elapsed between the rendering of such bill and the rendering of the most recent previous bill, whichever period is greater, shall be considered past due.

14.15 Bills rendered to non-residential customers on a billing month basis for which payment has not been received by the Company within 25 days from the date thereof – 55 days for bills rendered to the Commonwealth of Massachusetts, or any agency, city, town, county, or political subdivision thereof – shall be considered past due and bear interest as specified in Appendix B hereof on any unpaid balance from the date of the bill until the date of payment. The rate of interest shall be determined annually in accordance with the MDPU regulations at 220 C.M.R. 26.00 and shall become effective each year with February bills.

14.16 The Company may assess a Returned Check charge as specified in Appendix B to any Customer whose check made payable to the Company is dishonored by any bank when presented for payment by the Company.

14.17 In the event that the Company obtains inaccurate meter readings for any reason or in case any meter shall for any reason fail to register the full amount of Gas supplied or the maximum demand of any Customer for any period of time, the amount of the bill of such Customer shall be estimated by the Company from available data. Such estimates shall be binding upon both the Company and the Customer of record, unless a Customer of record disputes such estimate by following the billing and termination procedures of the MDPU. Such billing and termination procedures appear on the reverse side of each bill rendered by the Company for gas service.

14.18 Subject to law and the applicable regulations of the MDPU, security deposits may be required from new non-residential accounts; or from non-residential accounts for service of a similar

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character at any location under any name if this service has been properly terminated during the last eighteen (18) months due to non-payment; or if a non-residential account has failed to pay at least two bills, not reasonably in dispute within forty-five (45) days from the date of receipt of each such bill during the same 18-month period.

The maximum amount of any security deposit required shall not exceed the equivalent of either: 1) two billing months' average Gas Usage; or 2) the Gas Usage for any one billing month, whichever is greater. The security deposit, plus any accrued interest not previously credited to the account, shall be refunded without request if the Customer has paid all bills for Gas Usage for any twenty-four (24) month period from the date of deposit and without leaving such bills unpaid within forty-five (45) days of receipt.

Interest will be paid on all cash deposits held over six months at a rate equivalent to the rate paid on two-year United States Treasury notes for the preceding twelve (12) months ending December 31 of any year, or as otherwise determined by the MDPU. The Company may terminate a Customer's Distribution Service if the deposit is not made between ten (10) and fourteen (14) days' time after it has been requested in writing.

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15.0 DEFAULT SERVICE

15.1 Default Service is the supply service provided by the Company for Customers not electing to subscribe to Supplier Service and shall be provided by the Company or its designated supplier in accordance with tariffs approved by the MDPU. Each Customer receiving Default Service shall receive one bill from the Company reflecting unbundled charges for services.

15.2 A Customer receiving Default Service on October 31, 2000 shall continue to receive Default Service unless the Customer elects to take gas supply service from a Supplier and until such time that Supplier Service is initiated for the Customer in accordance with Section 24.5 of these Terms and Conditions. If said Customer terminates Supplier Service, if a Supplier terminates service to said Customer, or if said Customer's designated Supplier becomes ineligible to serve the Customer pursuant to Sections 11.6.5, 12.6.3, or 24.3 of these Terms and Conditions, the Company will provide Default Service to the Customer. Pursuant to Section 24.5 of these Terms and Conditions, the Company will initiate Default Service for the Customer and will provide Default Service to the Customer until such time that Supplier Service is initiated for the Customer by a new Supplier.

15.3 Any Customer whose Supplier has been assigned Capacity on behalf of said Customer pursuant to Section 13 of these Terms and Conditions may elect to return to Default Service if no longer receiving Supplier Service from a Supplier. If necessary, the Company will initiate Default Service for the Customer pursuant to Section 24.5 of these Terms and Conditions, and will provide the Customer with Default Service until such time that Supplier Service is initiated for the Customer by a new Supplier. The Company will provide Default Service to said Customer up to a maximum daily level of Gas Usage not to exceed the Total Capacity Quantity (TCQ) of recallable capacity assigned to the Customer's former Supplier.

15.4 In the event that a Supplier that has been assigned Capacity on behalf of a Customer pursuant to Section 13 of these Terms and Conditions terminates Supplier Service to said Customer, the Customer may select another Supplier. If necessary, the Company will initiate Default Service for the Customer pursuant to Section 24.5 of these Terms and Conditions, and will provide the Customer with Default Service until such time that Supplier Service is initiated for the Customer by a new Supplier. The Company will provide Default Service to said Customer up to a maximum daily level of Gas Usage not to exceed the TCQ of recallable capacity assigned to the Customer's former Supplier.

15.5 In the event that a Supplier that has been assigned Capacity on behalf of a Customer pursuant to Section 13 of these Terms and Conditions becomes ineligible to serve said Customer pursuant to Sections 11.6.5, 12.6.3, or 24.3 of these Terms and Conditions, the Company will provide the Customer with Default Service up to a maximum daily level of Gas Usage not to exceed the TCQ of recallable capacity assigned to the Customer's Supplier.

15.6 The Company shall be under no obligation to provide Default Service to a Customer at a maximum daily level in excess of the TCQ of recallable capacity assigned to a Supplier on behalf of said Customer. The Company may elect to provide Default Service to such Customer if, and to the extent that, adequate system capacity and supplies are available and upon the same terms and subject to the same conditions as any new Customer seeking to take Default Service.

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16.0 PEAKING SERVICE

16.1 Availability

Peaking Service is available 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 Sections 11 or 12, respectively, of these Terms and Conditions. Section 16 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.

16.2 Character of Service

16.2.1 Peaking Service shall be provided by the Company subject to an executed Supplier Service Agreement that sets forth the Maximum Daily Peaking Quantity (MDPQ) and the assigned Peaking Supply for each of the Supplier's Aggregation Pools.

16.2.2 The Company shall provide quantities of Gas, at the Supplier's request, from the Supplier's Peaking Service Account as established in accordance with Section 16.4. Such quantities shall be deemed delivered by the Company and received by the Company at the Designated Receipt Point(s) for the Aggregation Pool. Peaking Service shall be firm and available to the Supplier each Gas Day in accordance with the balance of the Supplier's Peaking Service Account and the parameters of the Company's Peaking Service Rule Curve.

16.3 Peaking Service Rate Components

16.3.1 The applicable rates for Peaking Service shall be established in the Company's tariffs as approved by the MDPU. The Supplier shall pay a peaking-demand charge based on its MDPQ of assigned Peaking Capacity as billed by the Company over the six (6) months of the Peak Season. Such unit-demand charge shall be equal to the total capacity costs and other fixed costs associated with the Company's peaking resources, excluding such costs that are collected through distribution rates, divided by the estimated peaking resources needed to meet the Company's total system Peak Day requirement.

16.3.2 The Supplier shall pay a commodity charge equal to the weighted average cost of peaking supplies plus fuel retention and carrying charges. The Company shall provide the Company's weighted average cost of peaking supplies electronically by the 15^{th} of the Month preceding the next Assignment Date. The commodity charge will be multiplied by the volumes of Peaking Service gas nominated by the Supplier during each Month.

16.4 Peaking Supply

16.4.1 The Customer's portion of the Peaking Supply that shall be assigned to the Supplier on behalf of the Customer shall be equal to the Peaking Supply multiplied by the ratio of the Customer's MDPQ to the aggregate MDPQ of the total system.

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16.4.2 On each Assignment Date, the Company shall assign Peaking Supply to a Supplier whose MDPQ has been increased pursuant to Section 13.4. If the Company assigns incremental Peaking Supply to a Supplier, the Company shall credit the balance of the Supplier's Peaking Service Account for volumes available through October 31 in accordance with the Peaking Service Rule Curve. The amount credited to the Supplier's Peaking Service Account shall be determined by multiplying the incremental Peaking Supply by the Peaking Inventory Percentage described in Section 16.4.5.

16.4.3 On each Assignment Date, the Company shall recall Peaking Supply from a Supplier whose MDPQ has been decreased pursuant to Section 13.7. The Company shall determine the Supplier's total Peaking Supply for recall to be equal to the difference between the cumulative total Peaking Supply assigned to the Supplier as of the previous Assignment Date and the total Peaking Supply that is assignable to the Supplier in the current Month in accordance with Section 16.4.1 above.

16.4.4 If the Company recalls Peaking Supply from a Supplier pursuant to Section 16.4.3, the Company shall debit the balance of the Supplier's Peaking Service Account for volumes available through October 31 in accordance with the Peaking Service Rule Curve. The amount debited from the Supplier's Peaking Service Account shall be determined by multiplying the decremental Peaking Supply by the Peaking Inventory Percentage described in Section 16.4.5.

16.4.5 The Peaking Inventory Percentage shall represent the level of Peaking Supply assumed to be available to a Supplier in its Peaking Service Account as of the first day of the Month following the Assignment Date for incremental and decremental assignments of Peaking Supply. Each September, the Company shall electronically provide the Peaking Inventory Percentages that shall be applied to incremental or decremental Peaking Supply assignments executed on each of the twelve Assignment Dates beginning in October.

16.4.6 On each Annual Reassignment Date, the Company shall reset the balance in the Supplier's Peaking Service Account to equal to the total Peaking Supply assignable to the Supplier on behalf of Customers enrolled in its Aggregation Pool (as of the first day of the Month following the Annual Reassignment Date) as determined in accordance with Section 16.4.1 above.

16.5 Nomination of Peaking Service

16.5.1 The Supplier shall nominate to the Company the quantity of Peaking Supply, not in excess of the amount determined pursuant to Section 16.4.2, that the Supplier desires to be provided from its Peaking Service Account for the applicable Day. For an Aggregation Pool of Customers taking Daily Metered Distribution Service, the notice given by the Supplier to the Company for an applicable Day shall be made in accordance with Section 11.3 of these Terms and Conditions. For an Aggregation Pool of Customers taking Non-Daily Metered Distribution Service, the notice given by the Supplier to the Company for an applicable Day shall be made in accordance with Section 12.3 of these Terms and Conditions.

16.5.2 In response to a valid nomination for Peaking Service, the Company shall provide the requested quantity of Gas which shall be deemed to be delivered by the Company and received by the Company at the Designated Receipt Point(s) of the Supplier's Aggregation Pool, subject to the limitations herein. Nominated quantities shall be included in the determination of receipts at the

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Designated Receipt Point(s) for the Supplier's Aggregation Pool which factors into the daily balancing provisions set forth in these Terms and Conditions.

16.5.3 The Company may reject a Supplier's nomination for Peaking Service if the nominated quantity would cause the balance of the Supplier's Peaking Service Account to fall to a level that is 10% or more below the minimum allowable account balance for the Month in which the nomination requested as computed in accordance with the Peaking Service Rule Curve. Under such circumstances, the Company shall require the Supplier to nominate the pipeline and/or storage resources, within the contract entitlements assigned to the Supplier under Section 13 hereof, required to maintain the Supplier's Peaking Service Account above the minimum allowable account balance described above. The balance of the Supplier's Peaking Service Account may not in any event fall below zero.

16.5.4 The Company shall provide Peaking Service supplies to the Supplier only when the volumes in the Peaking Service Account for the Aggregation Pool are greater than zero.

16.6 Peaking Service Critical Day Provisions

16.6.1 In the event that the volumes in a Supplier's Peaking Service Account for an Aggregation Pool are reduced to a level below the minimum allowable account balance as computed in accordance with the Company's Peaking Service Rule Curve, the Company may issue an OFO to such Supplier pursuant to Section 19 of these Terms and Conditions.

16.6.2 In the event that the total volumes of all Peaking Service Accounts within one or more of the Company's Gas Service Areas are reduced to levels below the total minimum allowable account balances as computed in accordance with the Company's Peaking Service Rule Curve, the Company may declare a Critical Day and issue a blanket OFO pursuant to Section 19 of these Terms and Conditions.

16.6.3 If, on a Critical Day, the Company projects, based on the Supplier's nominations, that the Supplier's scheduled deliveries to the Designated Receipt Points of an Aggregation Pool are less than the maximum feasible volumes for deliveries on the Delivering Pipeline, the Company may issue an OFO to the Supplier in accordance with Section 19 of these Terms and Conditions.

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17.0 INTERRUPTIBLE DISTRIBUTION SERVICE

17.1 Until such time that standardized terms and conditions for Interruptible Distribution Service are developed, the terms of customer-specific contracts shall establish the provision of such service by the Company.

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18.0 DISCONTINUANCE OF SERVICE

18.1 The Company may discontinue the supply of service and/or remove its equipment from the Customer's premise if the Customer fails to comply with the provisions of the Schedule of Rates or any supplementary or special agreement entered into with the Company, subject to any applicable billing and termination procedures of the MDPU. The Company may assess a non-residential Customer an Account Restoration Charge pursuant to Appendix B of these Terms and Conditions upon the Company restoring service after such discontinuance of supply. Any such charge must be paid as a precondition to restoration of service.

18.2 Whenever the Company reasonably determines that a Customer is diverting and/or stealing service, the Company may discontinue its service to such Customer and remove the meter.

18.3 The Company shall notify a Customer's Supplier of record that it has initiated any applicable billing and termination procedures of the MDPU. In the event that the Company discontinues Distribution Service to a Customer in accordance with the provisions set forth above, the Company shall provide electronic notification to the Customer's Supplier of record upon final billing to the Customer. The Company shall not be liable for any revenue loss to the Supplier as a result of any such disconnection.

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19.0 OPERATIONAL FLOW ORDERS AND CRITICAL DAYS

19.1 In the event of a material and significant threat to the operational integrity of the Company's system, the Company may declare a Critical Day.

19.2 Circumstances constituting a threat to the operational integrity of the system that may cause the Company to declare a Critical Day shall include, but not be limited to: (1) a failure of the Company's distribution, storage or production facilities; (2) near-maximum utilization of the Company's distribution, storage, production, and supply resources; (3) inability to fulfill firm service obligations; and (4) issuance of an OFO or similar notice by upstream transporters. A Critical Day may not be declared on all or a portion of the system for the purpose of maintaining interruptible services on that portion of the system, but interruptible gas may flow at times or on portions of the system when such flow would not violate any operational control restrictions or provisions of this Tariff.

19.3 In the event that the Company has declared a Critical Day, the Company will have the right to issue an OFO in which the Company may instruct Suppliers to take such action as conditions require, including, but not limited to, diverting Gas to or from the Company's distribution system, within the contract entitlements, if any, assigned to the Supplier under Section 13 hereof. An OFO may be issued on a pipeline or point-specific basis. An OFO may be issued by the Company as a blanket order to all Suppliers, or to an individual Supplier whose action is determined by the Company to jeopardize system integrity. The Company may issue an OFO to an individual Supplier if the Company faces gas cost exposure in excess of daily cashout or imbalance penalty revenues as set forth in Sections 11.6 and 12.6 for any under-deliveries or over-deliveries caused by that Supplier.

19.4 The Company will provide the Supplier with as much notice as is reasonably practicable of the issuance and removal of a Critical Day or an OFO; under most circumstances, the Company intends to provide at least twenty-two (22) hours' notice prior to the start of the Gas Day for the issuance of the Critical Day or OFO. Notification of the issuance and removal of a Critical Day or an OFO will be made on the Company's Website or by electronic means. The Supplier will be responsible for coordinating with its Customers regarding any necessary change to the Customer's quantity of Gas Usage. An OFO or Critical Day will remain in effect until its removal by the Company.

19.5 All quantities of Gas over-delivered or under-delivered to the Company's system in violation of an OFO will be subject to the Critical Day provisions of Sections 11.6 and 12.6 of these Terms and Conditions.

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20.0 FORCE MAJEURE AND LIMITATION OF LIABILITY

20.1 Neither the Company nor the Supplier will be liable for any act, omission, or circumstance occasioned by or in consequence of any event constituting Force Majeure, and unless it is otherwise expressly provided herein, the obligations of the Company and the Supplier then existing hereunder will be excused during the period thereof to the extent affected by such event of Force Majeure, provided that reasonable diligence is exercised to overcome such event. As used herein, Force Majeure will mean the inability of the Company or the Supplier to fulfill its contractual or regulatory obligations as a result of compliance by either party with an order, regulation, law, code, or operating standard imposed by a governmental authority; by reason of any act of God or public enemy; by reason of storm, flood, fire, earthquake, explosion, civil disturbance, labor dispute, breakage or accident to machinery or pipeline (which breakage or accident is not the result of the Company's negligence or misconduct); by reason of any declaration of Force Majeure by upstream transporting pipelines; or by reason of any other cause, whether the kind enumerated herein or otherwise, not within the control of the party claiming Force Majeure and which by the exercise of reasonable diligence such party is unable to prevent or overcome. Notwithstanding the foregoing, the Customer's and the Supplier's obligation to make any payments required under the applicable tariff or by these Terms and Conditions will in no case be excused by an event of Force Majeure. Nor will a failure to settle or prevent any labor dispute or other controversy with employees or with anyone purporting or seeking to represent employees be considered to be a matter within the control of the party claiming excuse. The party claiming Force Majeure will, on request, provide the other party with a written explanation thereof, and of the remedy being undertaken.

20.2 The Company shall be liable only for direct damages resulting from the Company's conduct of business when the Company, or its employees or agents have acted in a negligent or intentionally wrongful manner. In no event shall the Company be liable to any party for any indirect, consequential, or special damages, whether arising in tort, contract, or otherwise, by reason of any services performed, or undertaken to be performed, or actions taken by the Company, or its agents or employees, under the Schedule of Rates or in accordance with or required by law, including, without limitation, termination of the Customer's service.

20.3 If the Company is unable to render firm Distribution Service to the Customer taking such service as contemplated by these Terms and Conditions as a result of Force Majeure, and such inability continues for a period of thirty (30) days, the Customer may provide written notice to the Company of its desire to terminate Distribution Service at the expiration of thirty (30) days from the Company's receipt of such notice, but no sooner than sixty (60) days following the outset of the Force Majeure. If the Company has not restored Distribution Service to the Customer at the end of such notice period, the Customer's Distribution Service will terminate and both parties will be released from further performance hereunder, except for obligations to pay sums due and owing as of the date of termination. In such event, a Customer taking firm Distribution Service pursuant to Boston Gas Company Rate Schedules G-44 B, G-53E, or G-54 B, all of which include distribution-service demand charges, shall be eligible for an adjustment to the billed demand charges or a reimbursement of paid demand charges on a pro-rated basis to match the period in which the Company is unable to render Distribution Service as a result of the Force Majeure.

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20.4 Consistent with the provisions of Section 20.2 of these Terms and Conditions, the Company and the Supplier shall indemnify and hold the other and their respective affiliates, and the directors, officers, employees, and agents of each of them (collectively, "Affiliates") harmless from and against any and all losses, damages, costs (including reasonable attorney's fees), fines, penalties, and liabilities, in tort, contract, or otherwise (collectively, "Liabilities"), resulting from claims of third parties to the extent that such claims arise from negligent acts or omissions or willful misconduct in connection with the performance of obligations under these Terms and Conditions. No party shall be entitled to indemnification or be held harmless where its own negligent acts or omissions contribute to or cause such damages, costs, fines, penalties, or liabilities.

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21.0 CURTAILMENT

21.1 Whenever the integrity of the Company's system or the gas supply of the Company's Customers taking firm Default Service or Distribution Service is believed to be threatened by conditions on its system or upon the systems with which it is directly or indirectly interconnected, the Company may, in its sole reasonable judgment, curtail or interrupt gas service or reduce pressure and such action shall not be construed to constitute a default nor shall the Company be liable in any respect. The Company will use efforts reasonable under the circumstances to overcome the cause of such curtailment, interruption, or reduction and to resume full performance.

21.2 The Company shall post notice of curtailment as soon as practicable to the Suppliers of affected Customers via the Company's Website as identified in Section 23 or by alternative means as specified in the Supplier Service Agreement.

21.3 The Company shall take reasonable care in providing regular and uninterrupted service to its firm customers, but whenever the Company deems that the situation warrants any interruption or limitation in the service to be rendered, such interruption or limitation shall not constitute a breach of the contract, and shall not render the Company liable for any damages suffered thereby by any person, or excuse the Customer from further fulfillment of the contract.

21.4 If the Company is required to curtail or interrupt service due to capacity constraints, the Company's interruptible services shall have a priority subordinate to the Company's firm Distribution Service and Default Service Customers.

21.5 In any case where the Company determines in its judgment that a curtailment or interruption of firm services is necessary, the Company will curtail and/or interrupt Default Service and firm Distribution Service Customers on a nondiscriminatory basis consistent with the Company's curtailment policy or emergency plan, as is in effect and on file with the MDPU.

21.6 In the event service to a Customer is terminated or curtailed due to a failure to have Gas delivered to the Designated Receipt Point, the affected Customer will take all reasonable action to return to the taking of Distribution Service as rapidly as practicable.

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22.0 TAXES

22.1 In the event a tax of any kind is imposed or removed by any governmental authority on the transportation of Gas or on the gross revenues derived from the transportation of Gas at retail (exclusive, however, of taxes based on the Company's net income), the rate for service herein stated will be adjusted to reflect said tax. Similarly, the effective rate for service hereunder will be adjusted to reflect any refund of imposition of any surcharges or penalties applicable to service hereunder which are imposed or authorized by any governmental or regulatory authorities.

22.2 The Customer will be responsible for all taxes or assessments that may now or hereafter be levied with respect to the Gas or the handling or subsequent disposition thereof after its delivery to the Delivery Point. However, if the Company is required by law to collect and/or remit such taxes, the Customer will reimburse the Company for all amounts so paid. If the Customer claims exemption from any such taxes, the Customer will provide the Company in writing its tax exemption number and other appropriate documentation. If the Company collected any taxes or assessments from the Customer and is later informed by the Customer that the Customer is exempt from such taxes, it shall be the Customer's responsibility to obtain any refund from the appropriate governmental taxing agency.

22.3 The Supplier will be responsible for all production, severance, ad valorem, or similar taxes levied on the production or transportation of the Gas before its delivery to the Designated Receipt Point. The Supplier will also be responsible for sales taxes imposed on Gas delivered for the Customer's account. However, if the Company is required by law to remit such taxes to the collecting authority, it will do so and invoice the Supplier for such taxes paid on the Supplier's behalf.

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23.0 COMMUNICATIONS

All communications called for between a Supplier and the Company shall be made electronically, or by other alternative means as agreed to by the Company and the Supplier in the Supplier Service Agreement. Nominations shall be made utilizing the Company's EBB. Monthly metered customer information shall be transmitted via EDI.

The Company has the right to change the alternative mode of communication and will notify the Supplier of such change. Such a change shall not require filing of these Terms and Conditions with the MDPU.

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24.0 SUPPLIER TERMS AND CONDITIONS

24.1 Applicability

The following Terms and Conditions shall apply to every registered Supplier authorized to do business within the Commonwealth of Massachusetts, and to every Customer doing business with said Suppliers.

24.2 Obligations of Parties

24.2.1 Customer

Unless otherwise agreed to by the Company and the Customer, a Customer shall select one Supplier for each account at any given time. The Customer must provide the selected Supplier with its applicable account number. A Customer may choose only a Supplier who meets the terms described in Sections 24.2.3 and 24.3 below and who meets any applicable registration and licensing requirements established by law or regulation.

24.2.2 Company

The Company shall provide transportation of Customer-owned Gas from the Designated Receipt Point to the Delivery Point in accordance with the service selected by the Customer pursuant to Sections 11.0 or 12.0 of these Terms and Conditions and the applicable tariffs for firm and interruptible Distribution Service.

Pursuant to these Terms and Conditions and the Supplier Service Agreement, the Company shall offer Distribution Service, metering, billing, and information services for a Customer to purchase Supply Service from a Supplier, provided that the Supplier meets applicable registration and licensing requirements established by law or regulation. The Company is prohibited from providing these services to a Supplier that has not met applicable registration and licensing requirements established by law or regulation. In addition, the Company is prohibited from providing these services to a Supplier for a new Customer if the Supplier does not meet applicable registration and licensing requirements established by law or regulation.

The Company will also:

(1) Provide customer service and support, including call center functions, for services provided by the Company;

(2) Respond to service interruptions, reported gas leaks, and to other customer safety calls;

(3) Handle connections, curtailments, and terminations for services provided by the Company;

(4) Read meters;

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(5) Submit bills to Customers for Distribution Service, and if contracted by the Supplier, for Supplier Service in accordance with Section 14.2.1;

(6) Address billing inquiries for Distribution Service;

(7) Answer general questions about Distribution Service;

(8) Provide to Suppliers, on request, the data format and procedures for electronic information transfers and funds transfers;

(9) Provide to Customers, on request, a list of Suppliers that are qualified to operate on its system;

(10) Arrange for or provide Default Service to the Customer at the request of the Customer in accordance with the Company's tariff; and

(11) Provide information regarding, at minimum, rate tariffs, billing cycles, capacity assignment methods, and consumption algorithms, on its Website or by alternate electronic means.

24.2.3 Supplier

Each Supplier must meet the applicable registration and licensing requirements established by law or regulation.

The Supplier shall act on behalf of the Customer to acquire supplies and to deliver such supplies to the Designated Receipt Point pursuant to the service selected by the Customer and the requirements of the applicable tariff for Distribution Service.

The Supplier is responsible for enrolling customers pursuant to Section 24.5 of these Terms and Conditions.

The Supplier must request, complete, and sign a Supplier Service Agreement to act as a Supplier on the Company's system, satisfy the Supplier requirements and practices as set forth in Section 24.3 of these Terms and Conditions, be and remain an approved shipper on the upstream pipelines and underground storage facilities on which the Company will assign capacity, if any, under Section 13, and be and remain eligible to provide service to Customers in Massachusetts.

The Supplier is responsible for completing all transactions with the Company pursuant to Section 23, and for all applicable charges associated with Customer enrollment and changes in the Customer's service as set forth in Section 24.5 and Appendix B.

24.3 Supplier Requirements and Practices

24.3.1 The Company shall have the right to establish reasonable financial and non-discriminatory credit standards for qualifying Suppliers. A Supplier shall be deemed to satisfy the Company's creditworthiness requirements if the Supplier or a guarantor of the Supplier (1) maintains a

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minimum rating from one of the three rating agencies identified in the sentence following and (2) no rating below the minimum from one of the other two rating agencies. For purpose of this section, minimum rating shall mean "BBB" from Standard & Poor's, "Baa2" from Moody's Investor Service, or "BBB" from Fitch Ratings. If the Supplier does not meet these creditworthiness requirements, the Supplier shall provide the Company, on a confidential basis, with audited balance sheet and other financial statements, such as annual reports to shareholders and 10-K reports, for the previous three (3) years, as well as two (2) trade and two (2) banking references. To the extent that such annual reports and 10-K reports are not publicly available, the Supplier shall provide the Company with a comparable list of all corporate affiliates, parent companies, and subsidiaries. The Supplier shall also provide its most recent reports from credit reporting and bond rating agencies. The Supplier shall be subject to a credit investigation by the Company. The Company will review the Supplier's financial position periodically. If the Supplier is not publicly traded, the Supplier may submit other financial reports in order to meet the Company's review requirements.

24.3.2 The Supplier shall also confirm in the Supplier Service Agreement that:

(1) The Supplier is not operating under any chapter of bankruptcy laws and is not subject to liquidation or debt reduction procedures under state laws, such as an assignment for the benefit of creditors, or any information creditors' committee agreement.

(2) The Supplier is not aware of any change in business conditions which would cause a substantial deterioration in its financial conditions, a condition of insolvency, or the inability to exist as an ongoing business entity.

(3) The Supplier has no delinquent balances outstanding for services previously provided by the Company, and that the Supplier must have paid its account according to the established terms and not made deductions or withheld payment for claims not authorized by contract.

(4) No significant collection lawsuits or judgments are outstanding which would materially affect the Supplier's ability to remain solvent as a business entity.

(5) The Supplier's Massachusetts business advertising and marketing materials conform to all applicable Massachusetts state and federal laws and regulations.

24.3.3 In the event the Supplier has not demonstrated to the Company's satisfaction that it has met the Company's credit evaluation standards, the Company shall require the Supplier to provide one of the following at the Maximum Financial Liability as calculated below:

(a) Advance deposit;

(b) Letter of credit;

(c) Surety bond;

(d) Financial guaranty from a parent company that meets the creditworthiness criteria; or

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(e) Other means of providing or establishing adequate security that is acceptable to the Company.

The Company shall base the Supplier's Maximum Financial Liability as two (2) times the highest Month's aggregated Gas Usage of all Customers currently served by the Supplier at the highest Monthly Index in the preceding twenty-four (24) Months. This amount may be updated continuously, and at minimum, whenever the aggregated Gas Usage of all Customers served by the Supplier changes by more than 25%. The Supplier agrees that the Company has the right to access and apply the deposit, letter of credit, or bond to any payment of any outstanding claims that the Company may have against the Supplier, including imbalance charges, cash-out charges, pipeline penalty charges, and other amounts owed to the Company, or to secure additional gas supplies, including payment of the cost of the gas supplies, the cost of transportation storage, gathering, and other related costs incurred in bringing those gas supplies into the Company's system. The Supplier shall continue its obligation to maintain its financial security instrument until it has satisfied all of its outstanding claims of the Company. The Supplier's financial security as established above must be in place no later than five (5) Business Days prior to the first day of each calendar month in order for the Supplier to maintain its eligibility to provide service to Customers.

24.3.4 The Supplier shall warrant that it has or will have entered into the necessary arrangements for the purchase of gas supplies which it desires the Company to transport to its Customers, and that it has or will have entered into the necessary upstream transportation arrangements for the delivery of these gas supplies to the Designated Receipt Point.

24.3.5 The Supplier shall warrant to the Company that it has good title to or lawful possession of all Gas delivered to the Company at the Designated Receipt Point on behalf of the Supplier or the Supplier's Customers. The Supplier shall indemnify the Company and save it harmless from all suits, actions, debts, accounts, damage, costs, losses, taxes, and expenses arising from or out of any adverse legal claims of third parties to or against said gas supply.

24.3.6 The Supplier shall be responsible for making all necessary arrangements and securing all required regulatory or governmental approvals, certificates, or permits to enable Gas to be delivered to the Company's system.

24.3.7 By agreeing to provide service under these Terms and Conditions, the Supplier acknowledges that adherence to any applicable truth in advertising law is required. Any Supplier found by a court of competent jurisdiction to have willfully or repeatedly violated the Truth in Advertising Regulations, 940 C.M.R. 3.00 et seq.; 940 C.M.R. 6.00 et seq.; Federal Trade Commission Telemarketing Sales Rules, 16 C.F.R. Part 310; or the regulations promulgated pursuant to the Federal Trade Commission Act, 15 U.S.C. 45 (a) (1), may be suspended or disqualified from acting as a Supplier on the Company's system.

24.3.8 If the Supplier 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 (e.g., but not limited to failure to deliver Gas or late payment of bills rendered or failure to execute a capacity assignment), the Company maintains the right to terminate the Supplier's eligibility to act as a Supplier on the

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Company's system. Written notice of such an intent to terminate the Supplier's eligibility shall be given to both the Supplier and its Customers. Notification of the Supplier shall be via Registered U.S. Mail - Return Receipt Requested or other means of documented delivery. Upon issuance of such written notice, the Company shall have the right to terminate the Supplier's eligibility to act as a Supplier on the Company's system at the expiration of ten (10) days after the giving of such notice, unless within such ten (10) day period the Supplier shall remedy to the full satisfaction of the Company such failure. Termination of such Supplier eligibility for any such cause shall be a cumulative remedy as to the Company, and shall not release the Supplier from its obligation to make payment of any amount or amounts due or to become due from the Supplier to the Company under the Company's applicable tariffs. Customers whose Supplier's deliveries have been terminated will be placed on Default Service pursuant Section 15 of these Terms and Conditions.

24.4 Access to Usage History and Current Billing Information

The Company will provide EDI capability for non-Daily metered accounts to allow high volume transactions associated with account administration, usage and billing, and payments to be conducted electronically. Among the transactions which will be available are: enrollments, drops, adjustments, monthly usage, payment remittance, and historical usage. Detail information on EDI processing is available to Suppliers on request. All supplier EDI transaction sets will be tested prior to operational implementation.

The Supplier shall be responsible for obtaining the necessary authorization from each Customer prior to requesting the Company to release the Company's historic usage information specific to that Customer to such Supplier. Such authorization shall be validated using the customer account number and an EDI historical usage transaction.

The Company shall be required to provide the most recent twelve (12) months of a Customer's historic usage data to a Supplier, provided that the Supplier has received the appropriate authorization as set forth above. This information shall be provided in electronic form.

24.5 Enrollment, Cancellation, and Termination of Supplier Service

24.5.1 The Supplier shall be responsible for obtaining the necessary authorization in the form of the Customer's account number from each Customer prior to initiating Supplier Service to the Customer. Such authorization shall be in accordance with regulations established by the MDPU.

24.5.2 The Supplier must submit an EDI enrollment/drop to the Company with the following minimum information electronically in the Company's predetermined format prior to the commencement or termination of service by the Supplier pursuant to Section 24.5 of these Terms and Conditions:

(a) The Customer's account number;

(b) The Supplier's Dun and Bradstreet number;

(c) The Customer's billing option; and

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(d) Any additional information reasonably required by the Company.

The Company shall determine whether each Customer's electronic enrollment request as provided by a Supplier is complete and accurate, and matches the Customer's account record. In the event that the enrollment request is incomplete, inaccurate, or does not match the Customer's account record, then the Company will electronically notify the Supplier so that the Supplier can resolve any discrepancies. The Supplier shall not submit an electronic enrollment request until any applicable right of rescission has lapsed.

24.5.3 A change in Supplier Service will normally be made on a monthly metering and billing cycle basis, with changes taking effect on the date of the Customer's next scheduled meter read. Enrollment forms must be transmitted no less than ten (10) Business Days prior to the Customer's next scheduled meter read. If more than one Supplier submits an enrollment request for a given Customer during the monthly billing cycle, the first transaction that is received during the cycle shall be accepted. All other transactions shall be rejected. Rejected transactions may be resubmitted after the Customer's next scheduled meter read.

24.5.4 If the Supplier submits information to the Company to terminate Supplier Service to a Customer less than ten (10) Business Days before the next scheduled meter read, Supplier Service shall be terminated on the date of the Customer's subsequent scheduled meter read. The Company shall electronically confirm the termination date for Supplier Service.

24.5.5 To terminate Supplier Service with a Supplier and to initiate Default Service, a Customer shall so inform the Company and the Supplier. For residential customers, Supplier Service shall be terminated within two (2) Business Days following the date that the Customer informs the Company; for all other customers, Supplier Service shall be terminated on the date of the Customer's next scheduled meter read provided that the Company receives notice of such termination no less than ten (10) days in advance of the next scheduled meter read. Where such notice is received by the Company in less than ten (10) days in advance of the next scheduled read, the termination shall be effective as of the date of the following scheduled read. The Company shall send the Customer's termination date for Supplier Service to the Supplier.

24.5.6 In those instances when a Customer who is receiving Supplier Service from an existing Supplier initiates such service with a new Supplier, the Company shall send the date for Customer's change in Supplier Service to the existing Supplier.

24.5.7 A Customer who moves within the Company's service territory shall have the opportunity to notify its existing Supplier that it seeks to continue Supplier Service with said Supplier. Upon such notification, the Supplier may enroll the Customer pursuant to the provisions set forth in this section in order to initiate Supplier Service for the Customer at the new location. The Company shall make the necessary adjustments to the Supplier's affected Aggregation Pools, including but not limited to, changes to Designated Receipt Points, and quantities of capacity for assignment, if any, pursuant to these Terms and Conditions and the Supplier's Service Agreement with the Company. In the event that the existing Supplier does not enroll the Customer for Supplier Service at the new location, the Company shall arrange for or provide Default Service to the Customer.

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24.5.8 In those instances when a new Customer moves to the Company's service territory, the Customer's existing Supplier must enroll the Customer pursuant to the provisions set forth in this section in order to initiate Supplier Service for the Customer. Otherwise, the Customer shall receive Default Service in accordance with Section 15.

24.5.9 The Company may charge fees to the Supplier for processing the transactions described in this section, as approved by the MDPU. These fees are included in Appendix B.

24.6 Aggregation Pools

24.6.1 The aggregation of Customer accounts into an Aggregation Pool is limited by the Distribution Service of the respective Customers. Customers receiving Non-Daily Metered Distribution Service from the Company must be aggregated in a separate pool from Customers subscribing to Daily-Metered Distribution Service.

24.6.2 Within each of the Company's designated Service Areas, all Non-Daily Metered Customers served by a Supplier shall be aggregated by the Company into a single Aggregation Pool pursuant to Section 12 of these Terms and Conditions and the applicable tariffs.

24.6.3 Daily Metered Customers taking Distribution Service pursuant to Section 11 of these Terms and Conditions and the applicable tariffs can be combined by a Supplier into a single Aggregation Pool within each of the Company's designated Service Areas.

24.6.4 A separate Supplier Account will be established for each Supplier Aggregation Pool.

24.6.5 The election of any service from the Company by the Supplier shall apply to the entire Aggregation Pool and not just an individual customer in the Aggregation Pool.

24.6.6 The Company may charge a monthly fee to the Supplier for each Aggregation Pool pursuant to Appendix B.

24.7 Imbalance Trading

24.7.1 Prior to the imposition of imbalance charges, the Supplier may engage in trading daily and monthly imbalances for the previous Month, provided that Daily imbalance trades are communicated to the Company within three (3) Business Days upon the Company's provision of information on Supplier imbalances for said Month.

24.7.2 The Company will make available a list of Suppliers by Gas Service Area making deliveries during the previous Month.

24.7.3 Aggregation Pools affected by the transaction must be located within the same Gas Service Area as defined in Section 4, unless waived by the Company.

24.7.4 Daily imbalance trades must be point-specific on those days when the Delivering Pipeline required the Company to balance on a point-specific basis.

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24.8 Billing and Payment

By the tenth (10th) Business Day of the calendar month, the Company shall render to the Supplier a statement of the quantities delivered and amounts owed by the Supplier for the prior Month. The Company will provide Suppliers with their Customers' consumption data based on estimated or actual meter readings at the appropriate cycle read dates for each Customer in the Aggregation Pool pursuant to Section 14 of these Terms and Conditions. This data will be provided electronically on a rolling basis as readings or estimates are made.

Calculation of the charges applicable to the Aggregation Pool will be based on aggregated Gas Usage and other such indicators of all Customers in the Aggregation Pool. Billing for charges applicable to an Aggregation Pool, including but not limited to imbalance charges, credits or penalties, shall be billed to the Supplier on a calendar month basis.

The Supplier shall have ten (10) Business Days from the date of such statement to render payment to the Company. The Supplier shall render payment by means of electronic funds transfer to the Company. The late payment rate, as calculated pursuant to 220 C.M.R. 26.10, will apply to all amounts outstanding after ten days.

If the correctness of the Company's bill to the Supplier is questioned or disputed by the Supplier, an explanation should be promptly requested from the Company. If the bill is determined to be incorrect, the Company shall issue a corrected bill. In the event that the Supplier and the Company fail to agree on the amount of the bill, the Supplier shall follow the billing and termination procedures of the MDPU.

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25.0 CUSTOMER DESIGNATED REPRESENTATIVE

25.1 The Customer may appoint a Supplier as a Designated Representative to satisfy or undertake the Customer's following transportation duties and obligations: submitting and/or receiving notices on behalf of a Customer; making nominations on behalf of a Customer; arranging for trades of imbalances on behalf of a Customer as permitted under these Terms and Conditions; and performing operational and transportation-related administrative tasks on behalf of a Customer as permitted by the Company. Under no circumstances will the appointment of a Designated Representative relieve a Customer of the responsibility to make full and timely payment to the Company for all Distribution Service provided under these Terms and Conditions.

25.2 A request by the Supplier to the Company that contains the Customer's account number and the type of Customer authorization obtained in accordance with MDPU regulations pursuant to Section 24.5 of these Terms and Conditions will be deemed to be confirmation that the Customer has designated the Supplier as a Designated Representative. A Customer may appoint only one (1) Designated Representative per account.

25.3 Under any agency established hereunder, the Company shall rely upon information concerning the applicable Customer's Distribution Service which is provided by the Designated Representative. All such information shall be deemed to have been provided by the Customer. Similarly, any notice or other information provided by the Company to the Designated Representative concerning the provision of Distribution Service to such Customer shall be deemed to have been provided to the Customer. The Customer shall rely upon any information concerning Distribution Service that is provided to the Designated Representative as if that information had been provided directly to the Customer.

25.4 The Customer shall agree to indemnify the Company and hold it harmless from any liability (including reasonable legal fees and expenses) that the Company incurs as a result of the Designated Representative's negligence or willful misconduct in its performance of agency functions on the Customer's behalf.

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Algonquin Gas Service Area

		Pipeline	Storage	Peaking	Total
HLF	R-1 Res Non Heat	59.0%	10.0%	31.0%	100.0%
HLF	R-2 Res Non Heat-Subsidy	59.0%	10.0%	31.0%	100.0%
LLF	R-3 Res Heat	37.0%	15.0%	48.0%	100.0%
LLF	R-4 Res Heat-Subsidy	37.0%	15.0%	48.0%	100.0%
LLF	G-41B Com/Ind LLF Small	37.0%	15.0%	48.0%	100.0%
LLF	G-42B Com/Ind LLF Medium	37.0%	15.0%	48.0%	100.0%
LLF	G-43 B Com/Ind LLF Large	37.0%	15.0%	48.0%	100.0%
LLF	G-44 B Com/Ind LLF Xlarge	37.0%	15.0%	48.0%	100.0%
HLF	G-51 B Com/Ind HLF Small	59.0%	10.0%	31.0%	100.0%
HLF	G-52 B Com/Ind HLF Medium	59.0%	10.0%	31.0%	100.0%
HLF	G-53 B Com/Ind HLF Large	59.0%	10.0%	31.0%	100.0%
HLF	G-54 B Com/Ind HLF Xlarge	59.0%	10.0%	31.0%	100.0%
HLF	G-07 Street Lights	59.0%	10.0%	31.0%	100.0%
HLF	G-17 Gas Lights	59.0%	10.0%	31.0%	100.0%
HLF	High Load Factor	59.0%	10.0%	31.0%	100.0%
LLF	Low Load Factor	37.0%	15.0%	48.0%	100.0%

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Boston Gas

Tennessee Gas Service Area

		Pipeline	Storage	Peaking	Total
HLF	R-1 Res Non Heat	70.0%	10.0%	20.0%	100.0%
HLF	R-2 Res Non Heat - Subsidy	70.0%	10.0%	20.0%	100.0%
LLF	R-3 Res Heat	54.0%	16.0%	30.0%	101.0%
LLF	R-4 Res Heat-Subsidy	54.0%	16.0%	30.0%	101.0%
LLF	G-41B Com/Ind LLF Small	54.0%	16.0%	30.0%	101.0%
LLF	G-42B Com/Ind LLF Medium	54.0%	16.0%	30.0%	101.0%
LLF	G-43 B Com/Ind LLF Large	54.0%	16.0%	30.0%	101.0%
LLF	G-44 B Com/Ind LLF Xlarge	54.0%	16.0%	30.0%	101.0%
HLF	G-51 B Com/Ind HLF Small	70.0%	10.0%	20.0%	100.0%
HLF	G-52 B Com/Ind HLF Medium	70.0%	10.0%	20.0%	100.0%
HLF	G-53 B Com/Ind HLF Large	70.0%	10.0%	20.0%	100.0%
HLF	G-54 B Com/Ind HLF Xlarge	70.0%	10.0%	20.0%	100.0%
HLF	G-07 Street Lights	70.0%	10.0%	20.0%	100.0%
HLF	G-17 Gas Lights	70.0%	10.0%	20.0%	100.0%
HLF	High Load Factor	70.0%	10.0%	20.0%	100.0%
LLF	Low Load Factor	54.0%	16.0%	30.0%	100.0%

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Former Essex Gas

Tennessee Gas Service Area

		Pipeline	Storage	Peaking	Total
HLF	R-1 Non Heat	50.0%	8.0%	42.0%	100.0%
HLF	R-2 Non Heat-Subsidy	50.0%	8.0%	42.0%	100.0%
LLF	R-3 Res Heat	17.0%	13.0%	70.0%	100.0%
LLF	R-4 Res Heat-Subsidy	17.0%	13.0%	70.0%	100.0%
HLF	E-01 Gas Lights	50.0%	8.0%	42.0%	100.0%
LLF	G-41 E Com/Ind LLF Small	17.0%	13.0%	70.0%	100.0%
LLF	G-42 E Com/Ind LLF Medium	17.0%	13.0%	70.0%	100.0%
LLF	G-43 E Com/Ind LLF Large	17.0%	13.0%	70.0%	100.0%
HLF	G-51 E Com/Ind HLF Small	50.0%	8.0%	42.0%	100.0%
HLF	G-52 E Com/Ind HLF Medium	50.0%	8.0%	42.0%	100.0%
HLF	G-53 E Com/Ind HLF Large	50.0%	8.0%	42.0%	100.0%
HLF	High Load Factor	50.0%	8.0%	42.0%	100.0%
LLF	Low Load Factor	17.0%	13.0%	70.0%	100.0%

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Colonial Gas

Algonquin Gas Service Area

		Pipeline	Storage	Peaking	Total
HLF	R-1 Res Non Heat	80.0%	10.0%	10.0%	100.0%
HLF	R-2 Res Non Heat-Discount	80.0%	10.0%	10.0%	100.0%
LLF	R-3 Res Heat	69.0%	15.0%	16.0%	100.0%
LLF	R-4 Res Heat-Discount	69.0%	15.0%	16.0%	100.0%
LLF	G-41 Com/Ind LLF Small	69.0%	15.0%	16.0%	100.0%
LLF	G-42 Com/Ind LLF Medium	69.0%	15.0%	16.0%	100.0%
LLF	G-43 Com/Ind LLF Large	69.0%	15.0%	16.0%	100.0%
HLF	G-51 Com/Ind HLF Small	80.0%	10.0%	10.0%	100.0%
HLF	G-52 Com/Ind HLF Medium	80.0%	10.0%	10.0%	100.0%
HLF	G-53 Com/Ind HLF Large	80.0%	10.0%	10.0%	100.0%
HLF	High Load Factor	80.0%	10.0%	10.0%	100.0%
LLF	Low Load Factor	69.0%	15.0%	16.0%	100.0%

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Colonial Gas

Tennessee Gas Service Area

		Pipeline	Storage	Peaking	Total
HLF	R-1 Res Non Heat	46.0%	11.0%	43.0%	100.0%
HLF	R-2 Res Non Heat-Low Income	46.0%	11.0%	43.0%	100.0%
LLF	R-3 Res Heat	25.0%	16.0%	59.0%	100.0%
LLF	R-4 Res SSI Heat	25.0%	16.0%	59.0%	100.0%
LLF	G-41 Com/Ind LLF Small	25.0%	16.0%	59.0%	100.0%
LLF	G-42 Com/Ind LLF Medium	25.0%	16.0%	59.0%	100.0%
LLF	G-43 Com/Ind LLF Large	25.0%	16.0%	59.0%	100.0%
HLF	G-51 Com/Ind HLF Small	46.0%	11.0%	43.0%	100.0%
HLF	G-52 Com/Ind HLF Medium	46.0%	11.0%	43.0%	100.0%
HLF	G-53 Com/Ind HLF Large	46.0%	11.0%	43.0%	100.0%
HLF	High Load Factor	46.0%	11.0%	43.0%	100.0%
LLF	Low Load Factor	25.0%	16.0%	59.0%	100.0%

DISTRIBUTION SERVICE TERMS AND CONDITIONS

APPENDIX B

Schedule of Administrative Fees and Charges

Company Service Fees:

Customer Fees:

Interest charges for unpaid balances: The rate of interest shall be determined annually in accordance with the MDPU regulations at 220 C.M.R. 26.00 and shall become effective each year with February bills.

Returned Check Charge: $2.40

Account Restoration Charge: A commercial/industrial customer will be charged a reconnect charge of $118.00 if no court-issued warrant was obtained for shutoff. If a court issued warrant was obtained for shutoff, the commercial/industrial customer will be charged the cost of the warrant. All customers will be responsible for paying the additional reconnect costs if service is disconnected at the street.

Seasonal Reconnection Fee: $118.00

Paperless Bill Credit: $0.38/bill/month

Daily Metered Equipment Fee: A customer will be charged for the cost of equipment installed by the Company to provide Daily Metered Distribution Service through wireless readings of the Company's meter pursuant to Section 11.5.1. The initial lump sum charge is $1,201.00.

Daily Metered Data Plan Fee: A customer will be charged annually for the data plan associated with Daily Metered Distribution Service pursuant to Section 11.5.1. The annual data plan fee is $17.00.

Supplier Fees:

Customer Enrollment Fee (Section 24.5.9): TBD

Customer Cancellation and Termination Fee (Section 24.5.9): TBD

Aggregation Pool Fee (Section 24.6.6): TBD

Late Payment Charge (Section 24.8): The rate of interest shall be determined annually in accordance with the MDPU regulations at 220 C.M.R. 26.00.

Standard Complete Billing Service (Section 14.2.1): $0.97 per bill

Standard Passthrough Billing Service (Section 14.2.2): TBD

REVENUE DECOUPLING MECHANISM CLAUSE

<u>Section</u>

1.0 Purpose
2.0 Effective Date
3.0 Applicability
4.0 Definitions
5.0 Calculation of the Revenue Decoupling Reconciliation Amount
6.0 Calculation of the Prior Period Reconciliation Amount
7.0 Application of Revenue Decoupling Adjustment Factor to Bills
8.0 Information Required to be Filed with the Department

1.0 <u>Purpose</u>

The purpose of the Revenue Decoupling Mechanism Clause is to establish procedures that allow Boston Gas Company ("Boston" or the "Company") d/b/a National Grid subject to the jurisdiction of the Department of Public Utilities (the "Department") to adjust, on a semiannual basis, its rates for firm gas sales and firm transportation service in order to reconcile Actual Revenue per Customer with Benchmark Revenue per Customer as approved by the Department. The Revenue Decoupling Mechanism ("RDM") eliminates the link between customer sales and the Company's revenue in order to align the interests of the Company and customers with respect to lowering customer gas usage.

2.0 <u>Effective Date</u>

The Peak Period Revenue Decoupling Adjustment Factor ("RDAF") shall be effective on the first day of each Peak Period as defined herein. The Off-Peak RDAF shall become effective on the first day of each Off-Peak Period as defined herein.

3.0 <u>Applicability</u>

The Revenue Decoupling Mechanism shall apply to all the Company's firm tariff Rate Schedules, subject to the jurisdiction of the Department, as determined in accordance with the provisions of this tariff.

4.0 <u>Definitions</u>

The following definitions shall apply throughout the provisions of this RDM tariff:

(1) <u>Actual Revenue per Customer ("ARPC")</u> is the actual revenue derived from the Company's base distribution rates divided by the number of customers for a given season for a Customer Class Group exclusive of customers and associated revenues for customers connected to the Company's distribution system since the end of the test period for the Company's most recent base distribution rate case.

(2) <u>Actual Number of Customers ("ACUSTS")</u> is the actual number of customers for the applicable Customer Class Group for the most recently completed Peak or Off-Peak

REVENUE DECOUPLING MECHANISM CLAUSE

Period (T-1), exclusive of customers connected to the Company's distribution system since the end of the test period for the Company's most recent base distribution rate case.

(3) Base Rate Element is any customer, volumetric, or demand charge reflected in the Company's Rate Schedules that recovers a portion of the Company's base distribution revenue requirement as established in its most recent base distribution rate case or other proceeding that results in a base distribution rate change.

(4) Base Distribution Rates are the collection of Base Rate Elements for all the Company's Rate Schedules.

(5) Benchmark Revenue per Customer ("BRPC") is the allowed average Revenue per Customer for a given season for a Customer Class Group, reflecting the base distribution revenue for the Company's most recent base distribution rate case, adjusted annually pursuant to the Company's Performance-Based Ratemaking ("PBR") Tariff, M.D.P.U. No. 93.1, as may be amended from time to time, and as otherwise adjusted and approved by the Department, or from another proceeding that results in a base distribution rate change. The following are the Department approved benchmarks:

Effective December 1, 2021 in D.P.U. 20-120:

Customer Class Group	**Peak BRPC**	**Off Peak BRPC**
Residential Non-Heating	$152.15	$107.43
Residential Heating	$568.40	$128.33
Commercial & Industrial	$2,693.25	$755.94

Effective October 1, 2021 in D.P.U. 20-120:

Customer Class Group	**Peak BRPC**	**Off Peak BRPC**
Residential Non-Heating	$152.15	$107.43
Residential Heating	$570.96	$128.59
Commercial & Industrial	$2,698.72	$757.37

(6) Customer Class is the group of all customers taking service pursuant to the same Rate Schedule.

(7) Customer Class Group is the group of Rate Schedules combined for purposes of calculating the Revenue Decoupling Reconciliation Amounts. There are three Customer Class Groups as follows:

1. The Residential Heating Customer Class Group shall consist of all customers taking service pursuant to one of the Company's residential heating rate schedules.
2. The Residential Non-Heating Customer Class Group shall consist of all customers taking service pursuant to one of the Company's residential non-heating rate schedules.

REVENUE DECOUPLING MECHANISM CLAUSE

3. The Commercial and Industrial Customer Class Group shall consist of all sales and transportation customers taking service pursuant to one of the Company's general service G-40 and G-50 rate schedules.

(8) Distribution Revenue Allocator is derived from the Company's most recent base distribution rate case as approved by the Department and shall be as follows by Rate Class Grouping:

	Peak	Off Peak
Residential	68.2%	64.6%
Small Commercial and Industrial	7.2%	9.2%
Medium Commercial and Industrial	6.4%	7.3%
Large Commercial and Industrial	11.4%	13.9%
Extra Large Commercial and Industrial	6.8%	5.0%
Total	100.0%	100.0%

(9) Off-Peak Period is the continuous period from May 1 through October 31.

(10) Peak Period is the continuous period from November 1 through April 30.

(11) Rate Class Grouping is the grouping of similar rate classes to form the basis for the allocation of the Revenue Decoupling Reconciliation Amount. The Rate Class Groupings are defined as: Residential, Small Commercial and Industrial (Rate G-41 and Rate G-51 series), Medium Commercial and Industrial (Rate G-42 and Rate G-52 series), Large Commercial and Industrial (Rate G-43 and Rate G-53 series), and Extra Large Commercial and Industrial (Rate G-44 and Rate G-54 series).

5.0 Calculation of the Revenue Decoupling Reconciliation Amount

At the conclusion of each Peak or Off-Peak Period, the Company shall calculate a RDAF to be applied to customer bills in the next corresponding season. The RDAF for the Peak Period shall be applied to customer bills in the next Peak Period and the RDAF for the Off-Peak shall be applied to customer bills in the next Off-Peak Period.

The Revenue Decoupling Reconciliation Amount ("RDA") shall be calculated by comparing the difference between the ARPC and the BRPC for the applicable Customer Class Group and multiplying that difference by the ACUSTS for the applicable Customer Class Group. The sum of the differences calculated for each of the Customer Class Groups shall equal the total Company RDA and shall include a reconciliation component and carrying costs. If the RDA does not exceed the revenue cap described below, then it shall be allocated to each Rate Class Group by applying the Distribution Revenue Allocator and then divided by the Rate Class Group's seasonal forecasted throughput to derive the RDAF for each Rate Class Group.

The total Peak or Off-Peak RDA, including the prior period reconciliation, deferral amounts, and all carrying charges, may not exceed three percent (3%) of total revenue from firm sales and firm transportation throughput for the most recent corresponding Peak or Off-Peak Periods, here-in referred to as the Revenue Decoupling Cap ("RDC"), with transportation revenue adjusted by

REVENUE DECOUPLING MECHANISM CLAUSE

imputing the Company's cost of gas charges for that period. Total revenue shall include amounts that the Company has billed customers through applicable charges for distribution service, Local Distribution Adjustment Factors, Gas Adjustment Factors, and any related adjustment factors. If the RDA exceeds the RDC, then an amount equal to the RDC shall be allocated to each Rate Class Group by applying the Distribution Revenue Allocator and then divided by the Rate Class Group's seasonal forecasted throughput to derive the RDAF for each Rate Class Group. Amounts determined to be in excess of the RDC shall be deferred and included in the RDA reconciliation for recovery in the subsequent year during the corresponding Peak or Off-Peak Period as long as the sum of the RDA for that period, including the prior period reconciliation, deferral amounts, and all carrying charges, does not exceed the RDC for that period.

Carrying charges shall be calculated on the average deferred balance using the monthly prime lending rate, as reported by Bank of America. If the total amount of the RDA represents an over-recovery to be credited to customers, the entire amount is to be reflected in the RDAF at the beginning of the Peak or Off-Peak Periods (i.e., the RDC is applicable to the under-recoveries only; over-recoveries shall be credited in full).

$$\mathrm{RDA} = \left[\left(\sum_{cg=1}^{cg=n}\left((\mathrm{BRPC}_{T-1} - \mathrm{ARPC}_{T-1}) \text{ x } \mathrm{ACUSTS}_{T-1}\right)\right) + \mathrm{PPRA} + \mathrm{DEF}_{\mathrm{BALp}}\right] + \text{carrying costs}$$

If:

$RDA < \$0$

Then:

$DEF_{BALc} = \$0$

And:

$$RDAF_{S,T1} = \frac{RDA \text{ x } DRA_S}{TP_{VOLs}}$$

If:

$RDA > \$0$

And, if:

$RDA < RDC$

Then:

$DEF_{BALc} = \$0$

And:

$$RDAF_{S,T1} = \frac{RDA \text{ x } DRA_S}{TP_{VOLs}}$$

If:

$RDA > RDC$

REVENUE DECOUPLING MECHANISM CLAUSE

Then:

$$DEF_{BALc} = RDA - RDC$$

And:

$$RDAFs_{T1} = \frac{RDC \text{ x } DRA_S}{TP_{VOLs}}$$

For G-44 B, G-54 B, and G-53 E Rate Schedules only:

If:

$$RDA < \$0$$

Then:

$$RDAF_{S,T1} = \left(\frac{(RDA \text{ x } DRA_S)}{TP_{VOLs}}\right) \text{ x CF}$$

If:

$$RDA > \$0$$

And, if:

$$RDA < RDC$$

Then:

$$RDAF_{S,T1} = \left(\frac{(RDA \text{ x } DRA_S)}{TP_{VOLs}}\right) \text{ x CF}$$

If:

$$RDA > RDC$$

Then:

$$RDAF_{S,T1} = \left(\frac{(RDC \text{ x } DRA_S)}{TP_{VOLs}}\right) \text{ x CF}$$

Where:

RDAF:	The Revenue Decoupling Adjustment Factor for the Peak or Off-Peak Period (T-1).
DRA:	Distribution Revenue Allocator applicable to the Rate Class Group.
s:	Designates a separate factor for each Rate Class Group.
RDA:	The Revenue Decoupling Reconciliation Amount consisting of: (1) the difference between the BRPC and ARPC, with the difference multiplied by the ACUSTS, (2) the prior period reconciliation (PPRA), including interest, and, if applicable, (3) any deferral of RDA from prior periods (DEF_{BALp}) that the Company was not able to reflect in a prior period's RDAF, (4) any prospective carrying cost.
RDC:	The Revenue Decoupling Cap equal to three percent (3%) of total revenue from firm sales and firm transportation throughput for the most recent corresponding

REVENUE DECOUPLING MECHANISM CLAUSE

Peak or Off-Peak Period with transportation revenue being adjusted by imputing the Company's cost of gas charges for that period.

cg: Customer Class Groups 1 through n.

BRPC: Benchmark Revenue Per Customer for the applicable Customer Class Group as defined in Section 4.0 for the most recently completed Peak or Off-Peak Period (T-1).

ARPC: The Actual Revenue Per Customer for the applicable Customer Class Group for the most recently completed Peak or Off-peak Period (T-1), as defined in Section 4.0. For purposes of calculating the Actual Revenue per Customer, the non-discounted base distribution revenue prior to application of the low income discount shall be used.

ACUSTS: The actual number of customers for the applicable Customer Class Group for the most recently completed Peak or Off-Peak Period (T-1), exclusive of customers connected to the Company's distribution system since the end of the test period for the Company's most recent base distribution rate case.

TP_{Vol}: Forecast Throughput Volumes inclusive of all firm tariff sales and firm tariff transportation throughput for the Peak or Off-Peak Period.

PPRA: Prior Period Reconciliation Amount – Account 175.72 and Account 175.74, subsequent to the billing of applicable Peak or Off-Peak Period RDAF, including interest using the monthly prime lending rate, as reported by Bank of America.

DEF_{BALp}: The balance of the unrecovered deferrals from prior periods, including interest using the monthly prime lending rate, as reported by Bank of America.

DEF_{BALc}: The amount of RDA that must be deferred in the current year based on the difference between three percent (3%) of total revenue from firm sales and firm transportation throughput for the most recent corresponding Peak or Off-Peak Period, with transportation revenue adjusted by imputing the Company's cost of gas charges for that period, and the current year's RDA.

CF: Factor to convert volumetric rate into a Maximum Daily Contract rate based on billing determinants from most recent base distribution rate case.

Rate Schedule	Peak Period CF	Off-Peak Period CF
G-44 B	14.2493	14.1181
G-54 B / G-53 E	16.5652	17.5941

6.0 <u>Calculation of the Prior Period Reconciliation Amount</u>

(1) The following definitions pertain to prior period reconciliation amount calculations:

(i) <u>Revenue Decoupling Reconciliation Amount Allowable</u> shall be:

i. Semi-annual base revenue reconciliation associated with the RDA.
ii. Account 175.72 Peak Period RDA interest costs.
iii. Account 175.74 Off-Peak Period RDA interest costs.

(2) Calculation of the Prior Period Reconciliation Amount:

REVENUE DECOUPLING MECHANISM CLAUSE

Account 175.72 shall contain the accumulated difference between revenue toward the RDA for the Peak Period, as calculated by multiplying the Peak Period RDAF times the Peak Period firm sales and transportation throughput for volumetric based rate schedules and the Peak Period RDAF for the G-44 B, G-54 B, and G-53 E rate schedules times the Peak Period firm sales and transportation monthly Maximum daily contract quantity, and the RDA allowed for the Peak Period, plus carrying charges on the average monthly balance using the monthly prime lending rate, as reported by Bank of America. Account 175.72 shall also include Peak Period deferrals as determined in Section 5.0.

Account 175.74 shall contain the accumulated difference between revenue toward the RDA for the Off-Peak Period, as calculated by multiplying the Off-Peak Period RDAF times the Off-Peak Period firm sales and transportation throughput for volumetric based rate schedules and the Off-Peak Period RDAF for the G-44 B, G-54 B, and G-53 E rate schedules times the Off-Peak Period firm sales and transportation monthly Maximum daily contract quantity, and the RDA allowed for the Off-Peak Period, plus carrying charges on the average monthly balance using the monthly prime lending rate, as reported by Bank of America. Account 175.74 shall also include Off-Peak Period deferrals as determined in Section 5.0.

7.0 Application of Revenue Decoupling Adjustment Factor to Bills

Any RDAF ($ per therm) shall be truncated to the nearest one one-hundredth of a cent per therm. The RDAF for the Peak Period will be applied to customer bills in the next Peak Period and the RDAF for the Off-Peak Period will be applied to customer bills in the next Off-Peak Period. The RDAF will be applied to the MDCQ for G-44 B, G-54 B, and G-53 E customers and to monthly firm sales and firm transportation throughput for all other customers.

8.0 Information Required to be Filed with the Department

Information pertaining to the RDA will be filed with the Department ninety (90) days prior to the effective dates of the November 1 Peak or May 1 Off-Peak Period RDAF. Such information shall include the calculation of the applicable revenue decoupling reconciliation amount and prior period reconciliation amount, including a summary and schedules as set out in Exhibit A to Revenue Decoupling Adjustment Factor Filing Procedures, D.P.U. 14-RDAF-01 (2014). Other information shall include for the pertinent period the following:

(1) Billed sales data by customer class
(2) Forecasted volumes by rate class
(3) Bill impact comparison, by customer class, of proposed rates to current rates and of proposed rates to rates in effect for the prior pertinent period
(4) Estimate of lost base revenue ("LBR")
(5) Capital costs associated with new customers
(6) Weather-normalized sales data by customer class
(7) Weather-normalized RDA
(8) Other information schedules as prescribed by the Department from time to time

Residential Non-Heating Rate
Classification No. R-1

Availability:

Available to all residential customers who do not have gas space heating equipment. Excludes institutions, hotels, apartments, condominiums, and rooming houses in which the individual tenants are not billed separately. Available for gas supplied through one meter for all residential non-heating appliances used in common by the tenants of a single building which contains not more than four (4) dwelling units.

Character of Service:

Natural gas containing not less than 960 B.T.U. per cubic foot.

Distribution Service Rate:

Customer Charge:	$10.00 per 30 Day Month
Energy Charge during the months of:	
November - April	$0.9636 per Therm
May - October	$0.8762 per Therm

Other Charges for Distribution Service and Minimum Charge:

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause (LDAC), Revenue Decoupling Adjustment Clause (RDA), and Performance-Based Ratemaking (PBR) Plan filings, as in effect from time to time and on file with Massachusetts Department of Public Utilities (Department). The minimum charge per month shall be the Customer Charge.

Supply Charges:

If the customer purchases its gas from a third party, supply charges will be as agreed upon between the customer and the third party supplier (and may be billed directly by the third party supplier or through the Company as a separate item in the Company's bills to the customer). If the customer does not purchase its gas from a third party, it will receive Default Service from the Company and will pay the costs set forth in the Company's Cost of Gas Adjustment Clause (CGAC) in effect from time to time and on file with the Department.

Terms and Conditions of Distribution Service:

As in effect from time to time.

Residential Non-Heating Rate
Classification No. R-1

Farm Discount:

A customer who is certified annually by the Department of Food and Agriculture as being eligible for the Farm Discount Program will receive a discount in the amount of ten (10) percent from the charges set forth in this rate schedule.

Residential Assistance Non-Heating Rate
Classification No. R-2

Availability:

Gas delivery service under this rate is available upon verification of a low-income Customer's receipt of any means-tested benefit, or verification of eligibility for the low-income home energy assistance program, or its successor program, for which eligibility does not exceed 200 percent of the federal poverty level based on a household's gross income. In a program year in which maximum eligibility for LIHEAP exceeds 200 percent of the federal poverty level, a household that is income eligible under LIHEAP shall be eligible for the low-income discount. The customer must be 18 years of age or older, head of household, a residential customer of record, and not have gas space heating equipment. It is the responsibility of the customer to certify annually to the utility, on forms provided by the utility, the customer's continued eligibility for the low-income rate.

This rate is available only to residential customers and excludes institutions, hotels, apartments, and rooming houses in which the individual tenants are not billed separately.

Character of Service:

Natural gas containing not less than 960 B.T.U. per cubic foot.

Distribution Service Rate:

Customer Charge:	$10.00 per 30 Day Month
Energy Charge during the months of:	
November - April	$0.9636 per Therm
May - October	$0.8762 per Therm

Other Charges for Distribution Service and Minimum Charge:

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause (LDAC), Revenue Decoupling Adjustment Clause (RDA), and Performance-Based Ratemaking (PBR) Plan filings, as in effect from time to time and on file with Massachusetts Department of Public Utilities (Department). The minimum charge per month shall be the Customer Charge.

Supply Charges:

If the customer purchases its gas from a third party, supply charges will be as agreed upon between the customer and the third party supplier (and may be billed directly by the third party supplier or through the Company as a separate item in the Company's distribution to the customer). If the customer does not purchase its gas from a third party, it will receive Default Service from the Company and will pay the costs set forth in the Company's Cost of Gas Adjustment Clause (CGAC) in effect from time to time and on file with the Department.

Residential Assistance Non-Heating Rate
Classification No. R-2

Terms and Conditions of Distribution Service:

As in effect from time to time.

Farm Discount:

A customer who is certified annually by the Department of Food and Agriculture as being eligible for the Farm Discount Program will receive a discount in the amount of ten (10) percent from the charges set forth in this rate schedule.

Low Income Discount:

The total amount resulting from billing of all charges under this rate shall be adjusted by a discount of 25 percent.

Residential Heating Rate
Boston Division
Classification No. R-3B

Availability:

Available to all residential customers located in the Boston Division service territory who have gas space heating equipment. Excludes institutions, hotels, apartments, and rooming houses in which the individual tenants are not billed separately. Available for gas supplied through one meter for all residential appliances used in common by the tenants of a single building which contains not more than four (4) dwelling units, provided gas is the primary space heating fuel.

Character of Service:

Natural gas containing not less than 960 B.T.U. per cubic foot.

Distribution Service Rate:

Customer Charge:	$12.00 per 30 Day Month
Energy Charge during the months of:	
November - April	$0.6885 per Therm
May - October	$0.3401 per Therm

Other Charges for Distribution Service and Minimum Charge:

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause (LDAC), Revenue Decoupling Adjustment Clause (RDA), and Performance-Based Ratemaking (PBR) Plan filings, as in effect from time to time and on file with Massachusetts Department of Public Utilities (Department). The minimum charge per month shall be the Customer Charge.

Supply Charges:

If the customer purchases its gas from a third party, supply charges will be as agreed upon between the customer and the third party supplier (and may be billed directly by the third party supplier or through the Company as a separate item in the Company's bills to the customer). If the customer does not purchase its gas from a third party, it will receive Default Service from the Company and will pay the costs set forth in the Company's Cost of Gas Adjustment Clause (CGAC) in effect from time to time and on file with the Department.

Terms and Conditions of Distribution Service:

As in effect from time to time.

Residential Heating Rate
Boston Division
Classification No. R-3B

Farm Discount:

A customer who is certified annually by the Department of Food and Agriculture as being eligible for the Farm Discount Program will receive a discount in the amount of ten (10) percent from the charges set forth in this rate schedule.

Residential Heating Rate
Colonial Division
Classification No. R-3C

Availability:

Available to all residential customers located in the Colonial Division service territory who have gas space heating equipment. Excludes institutions, hotels, apartments and rooming houses in which the individual tenants are not billed separately. Available for gas supplied through one meter for all residential appliances used in common by the tenants of a single building which contains not more than three (3) dwelling units, provided gas is the primary space heating fuel

Character of Service:

Natural gas containing not less than 960 B.T.U. per cubic foot.

Distribution Service Rate:

Customer Charge	$12.00 per 30 Day Month
Energy Charge during the billing months of:	
November – April	$0.5643 per Therm
May – October	$0.4335 per Therm

Other Charges For Distribution Service and Minimum Charge:

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause (LDAC), Revenue Decoupling Adjustment Clause (RDA), and Performance-Based Ratemaking (PBR) Plan filings, as in effect from time to time and on file with the Massachusetts Department of Public Utilities (Department). The minimum charge per month shall be the Customer Charge.

Supply Charges:

If the customer purchases its gas from a third party, supply charges will be as agreed upon between the customer and the third party supplier (and may be billed directly by the third party supplier or through the Company as a separate item in the Company's bills to the customer). If the customer does not purchase its gas from a third party, it will receive Default Service from the Company and will pay the costs set forth in the Company's Cost of Gas Adjustment Clause (CGAC) in effect from time to time and on file with the Department.

Terms and Conditions of Distribution Service:

As in effect from time to time.

Residential Heating Rate
Colonial Division
Classification No. R-3C

Farm Discount:

A customer who is certified annually by the Department of Food and Agriculture as being eligible for the Farm Discount Program will receive a discount in the amount of ten (10) percent from the charges set forth in this rate schedule.

Residential Assistance Heating Rate
Boston Division
Classification No. R-4B

Availability:

Gas delivery service under this rate is available upon verification of a low-income Customer's receipt of any means-tested benefit, or verification of eligibility for the low-income home energy assistance program, or its successor program, for which eligibility does not exceed 200 percent of the federal poverty level based on a household's gross income. In a program year in which maximum eligibility for LIHEAP exceeds 200 percent of the federal poverty level, a household that is income eligible under LIHEAP shall be eligible for the low-income discount. The customer must be 18 years of age or older, head of household, a residential customer of record, and have gas space heating equipment. It is the responsibility of the customer to certify annually to the utility, on forms provided by the utility, the customer's continued eligibility for the low-income rate.

This rate is available only to residential customers located in the Boston Division service territory and excludes institutions, hotels, apartments, and rooming houses in which the individual tenants are not billed separately.

Character of Service:

Natural gas containing not less than 960 B.T.U. per cubic foot.

Distribution Service Rate:

Customer Charge:	$12.00 per 30 Day Month
Energy Charge during the months of:	
November - April	$0.6885 per Therm
May - October	$0.3401 per Therm

Other Charges for Distribution Service and Minimum Charge:

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause (LDAC), Revenue Decoupling Adjustment Clause (RDA), and Performance-Based Ratemaking (PBR) Plan filings, as in effect from time to time and on file with Massachusetts Department of Public Utilities (Department). The minimum charge per month shall be the Customer Charge.

Supply Charges:

If the customer purchases its gas from a third party, supply charges will be as agreed upon between the customer and the third party supplier (and may be billed directly by the third party supplier or through the Company as a separate item in the Company's bills to the customer). If the customer does not purchase its gas from a third party, it will receive Default Service from the Company and will pay the costs set

Residential Assistance Heating Rate
Boston Division
Classification No. R-4B

forth in the Company's Cost of Gas Adjustment Clause (CGAC) in effect from time to time and on file with the Department.

Terms and Conditions of Distribution Service:

As in effect from time to time.

Farm Discount:

A customer who is certified annually by the Department of Food and Agriculture as being eligible for the Farm Discount Program will receive a discount in the amount of ten (10) percent from the charges set forth in this rate schedule.

Low Income Discount:

The total amount resulting from billing of all charges under this rate shall be adjusted by a discount of 25 percent.

Residential Assistance Heating Rate
Colonial Division
Classification No. R-4C

Availability:

Gas delivery service under this rate is available upon verification of a low-income Customer's receipt of any means-tested benefit, or verification of eligibility for the low-income home energy assistance program, or its successor program, for which eligibility does not exceed 200 percent of the federal poverty level based on a household's gross income. In a program year in which maximum eligibility for LIHEAP exceeds 200 percent of the federal poverty level, a household that is income eligible under LIHEAP shall be eligible for the low-income discount. The customer must be 18 years of age or older, head of household, a residential customer of record, and have gas space heating equipment. It is the responsibility of the customer to certify annually to the utility, on forms provided by the utility, the customer's continued eligibility for the low-income rate.

This rate is available only to residential customers located in the Colonial Division service territory and excludes institutions, hotels, apartments, and rooming houses in which the individual tenants are not billed separately.

Character of Service:

Natural gas containing not less than 960 B.T.U. per cubic foot.

Distribution Service Rate:

Customer Charge	$12.00 per 30 Day Month
Energy Charge during the billing months of:	
November – April	$0.5643 per Therm
May – October	$0.4335 per Therm

Other Charges For Distribution Service and Minimum Charge:

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause (LDAC), Revenue Decoupling Adjustment Clause (RDA), and Performance-Based Ratemaking (PBR) Plan filings, as in effect from time to time and on file with the Massachusetts Department of Public Utilities (Department). The minimum charge per month shall be the Customer Charge.

Supply Charges:

If the customer purchases its gas from a third party, supply charges will be as agreed upon between the customer and the third party supplier (and may be billed directly by the third party supplier or through the Company as a separate item in the Company's bills to the customer). If the customer

Residential Assistance Heating Rate
Colonial Division
Classification No. R-4C

does not purchase its gas from a third party, it will receive Default Service from the Company and will pay the costs set forth in the Company's Cost of Gas Adjustment Clause (CGAC) in effect from time to time and on file with the Department.

Terms and Conditions of Distribution Service:

As in effect from time to time.

Farm Discount:

A customer who is certified annually by the Department of Food and Agriculture as being eligible for the Farm Discount Program will receive a discount in the amount of ten (10) percent from the charges set forth in this rate schedule.

Low Income Discount:

The total amount resulting from billing of all charges under this rate shall be adjusted by a discount of 25 percent.

Low Load Factor General Service Rate – Small
Boston Division
Classification No. G-41B

Availability:

Available to commercial, industrial, and institutional customers located in the Boston Division service territory whose metered use in the most recent peak period of November through April is greater than or equal to seventy (70) percent of the metered use for the most recent twelve consecutive months of September through August, and whose maximum hourly meter capacity is less than or equal to 500 cubic feet per hour.

In the case of a new customer, or a customer with new gas applications, the peak percentage classification for the first year shall be that agreed upon by the Company and the Customer.

Character of Service:

Natural gas containing not less than 960 B.T.U. per cubic foot.

Distribution Service Rate:

Customer Charge:	$26.00 per 30 Day Month
Energy Charge during the months of:	
November - April	$0.5275 per Therm
May - October	$0.4275 per Therm

Other Charges for Distribution Service and Minimum Charge:

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause (LDAC), Revenue Decoupling Adjustment Clause (RDA), and Performance-Based Ratemaking (PBR) Plan filings, as in effect from time to time and on file with Massachusetts Department of Public Utilities (Department). The minimum charge per month shall be the Customer Charge.

Supply Charges:

If the customer purchases its gas from a third party, supply charges will be as agreed upon between the customer and the third party supplier (and may be billed directly by the third party supplier or through the Company as a separate item in the Company's bills to the customer). If the customer does not purchase its gas from a third party, it will receive Default Service from the Company and will pay the costs set forth in the Company's Cost of Gas Adjustment Clause (CGAC) in effect from time to time and on file with the Department.

Terms and Conditions of Distribution Service:

As in effect from time to time.

Low Load Factor General Service Rate – Small
Boston Division
Classification No. G-41B

Farm Discount:

A customer who is certified annually by the Department of Food and Agriculture as being eligible for the Farm Discount Program will receive a discount in the amount of ten (10) percent from the charges set forth in this rate schedule.

Low Load Factor General Service Rate – Small
Colonial Division
Classification No. G-41C

Availability:

Available to commercial, industrial, and institutional customers located in the Colonial Division service territory whose metered use in the most recent peak period of November through April is greater than or equal to seventy- two percent (72%) of the metered use for the most recent twelve consecutive months of September through August, and whose metered annual usage is 20,000 Therms (billing units) or less.

In the case of a new customer, or a customer with new gas applications, the peak percentage classification for the first year shall be that agreed upon by the Company and the Customer.

Character of Service:

Natural gas containing not less than 960 B.T.U. per cubic foot.

Distribution Service Rate:

Customer Charge	$19.00 per 30 Day Month
Energy Charge during the billing months of:	
November – April	$0.4275 per Therm
May – October	$0.3479 per Therm

Other Charges For Distribution Service and Minimum Charge:

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause (LDAC), Revenue Decoupling Adjustment Clause (RDA), and Performance-Based Ratemaking (PBR) Plan filings, as in effect from time to time and on file with the Massachusetts Department of Public Utilities (Department). The minimum charge per month shall be the Customer Charge.

Supply Charges:

If the customer purchases its gas from a third party, supply charges will be as agreed upon between the customer and the third party supplier (and may be billed directly by the third party supplier or through the Company as a separate item in the Company's bills to the customer). If the customer does not purchase its gas from a third party, it will receive Default Service from the Company and will pay the costs set forth in the Company's Cost of Gas Adjustment Clause (CGAC) in effect from time to time and on file with the Department.

Low Load Factor General Service Rate – Small
Colonial Division
Classification No. G-41C

Terms and Conditions of Distribution Service:

As in effect from time to time.

Farm Discount:

A customer who is certified annually by the Department of Food and Agriculture as being eligible for the Farm Discount Program will receive a discount in the amount of ten (10) percent from the charges set forth in this rate schedule.

Low Load Factor General Service Rate – Small
Essex Division
Classification No. G-41E

Availability:

Available to commercial, industrial, and institutional customers located in the former Essex service territory whose metered use in the most recent peak period of November through April is greater than or equal to seventy-three (73) percent of the metered use for the most recent twelve consecutive months of September through August, and whose normal annual use is 22,000 Therms or less.

In the case of a new customer, or a customer with new gas applications, the peak percentage classification for the first year shall be that agreed upon by the Company and the Customer.

Character of Service:

Natural gas containing not less than 960 B.T.U. per cubic foot.

Distribution Service Rate:

Customer Charge:	$26.00 per 30 Day Month
Energy Charge during the months of:	
November - April	$0.4814 per Therm
May - October	$0.3944 per Therm

Other Charges for Distribution Service and Minimum Charge:

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause (LDAC), Revenue Decoupling Adjustment Clause (RDA), and Performance-Based Ratemaking (PBR) Plan filings, as in effect from time to time and on file with Massachusetts Department of Public Utilities (Department). The minimum charge per month shall be the Customer Charge.

Supply Charges:

If the customer purchases its gas from a third party, supply charges will be as agreed upon between the customer and the third party supplier (and may be billed directly by the third party supplier or through the Company as a separate item in the Company's bills to the customer). If the customer does not purchase its gas from a third party, it will receive Default Service from the Company and will pay the costs set forth in the Company's Cost of Gas Adjustment Clause (CGAC) in effect from time to time and on file with the Department.

Terms and Conditions of Distribution Service:

As in effect from time to time.

Low Load Factor General Service Rate – Small
Essex Division
Classification No. G-41E

Farm Discount:

A customer who is certified annually by the Department of Food and Agriculture as being eligible for the Farm Discount Program will receive a discount in the amount of ten (10) percent from the charges set forth in this rate schedule.

Low Load Factor General Service Rate – Medium
Boston Division
Classification No. G-42B

Availability:

Available to commercial, industrial, and institutional customers located in the Boston Division service territory whose metered use in the most recent peak period of November through April is greater than or equal to seventy (70) percent of the metered use for the most recent twelve consecutive months of September through August, and whose maximum hourly meter capacity is between 501 and 1,500 cubic feet per hour.

In the case of a new customer, or a customer with new gas applications, the peak percentage classification for the first year shall be that agreed upon by the Company and the Customer.

Character of Service:

Natural gas containing not less than 960 B.T.U. per cubic foot.

Distribution Service Rate:

Customer Charge:	$48.00 per 30 Day Month
Energy Charge during the months of:	
November - April	$0.5234 per Therm
May - October	$0.4203 per Therm

Other Charges for Distribution Service and Minimum Charge:

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause (LDAC), Revenue Decoupling Adjustment Clause (RDA), and Performance-Based Ratemaking (PBR) Plan filings, as in effect from time to time and on file with Massachusetts Department of Public Utilities (Department). The minimum charge per month shall be the Customer Charge.

Supply Charges:

If the customer purchases its gas from a third party, supply charges will be as agreed upon between the customer and the third party supplier (and may be billed directly by the third party supplier or through the Company as a separate item in the Company's bills to the customer). If the customer does not purchase its gas from a third party, it will receive Default Service from the Company and will pay the costs set forth in the Company's Cost of Gas Adjustment Clause (CGAC) in effect from time to time and on file with the Department.

Terms and Conditions of Distribution Service:

As in effect from time to time.

Low Load Factor General Service Rate – Medium
Boston Division
Classification No. G-42B

Farm Discount:

A customer who is certified annually by the Department of Food and Agriculture as being eligible for the Farm Discount Program will receive a discount in the amount of ten (10) percent from the charges set forth in this rate schedule.

Low Load Factor General Service Rate – Medium
Colonial Division
Classification No. G-42C

Availability:

Available to commercial, industrial and institutional customers located in the Colonial Division service territory whose metered use in the most recent peak period of November through April is greater than or equal to seventy-two percent (72%) of the metered use for the most recent twelve consecutive months of September through August, and whose metered annual gas usage is greater than or equal to 20,000 and less than or equal to 100,000 Therms (billing units).

In the case of a new customer, or a customer with new gas applications, the peak percentage classification for the first year shall be that agreed upon by the Company and the Customer.

Character of Service:

Natural gas containing not less than 960 B.T.U. per cubic foot.

Distribution Service Rate:

Customer Charge	$48.00 per 30 Day Month
Energy Charge during the billing months of:	
November – April	$0.3851 per Therm
May – October	$0.3372 per Therm

Other Charges for Distribution Service and Minimum Charge:

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause (LDAC), Revenue Decoupling Adjustment Clause (RDA), and Performance-Based Ratemaking (PBR) Plan filings, as in effect from time to time and on file with the Massachusetts Department of Public Utilities (Department). The minimum charge per month shall be the Customer Charge.

Supply Charges:

If the customer purchases its gas from a third party, supply charges will be as agreed upon between the customer and the third party supplier (and may be billed directly by the third party supplier or through the Company as a separate item in the Company's distribution to the customer). If the customer does not purchase its gas from a third party, it will receive Default Service from the Company and will pay the costs set forth in the Company's Cost of Gas Adjustment Clause (CGAC) in effect from time to time and on file with the Department.

Low Load Factor General Service Rate – Medium
Colonial Division
Classification No. G-42C

Terms and Conditions of Distribution Service:

As in effect from time to time.

Farm Discount:

A customer who is certified annually by the Department of Food and Agriculture as being eligible for the Farm Discount Program will receive a discount in the amount of ten (10) percent from the charges set forth in this rate schedule.

Low Load Factor General Service Rate – Medium
Essex Division
Classification No. G-42E

Availability:

Available to commercial, industrial, and institutional customers located in the former Essex service territory whose metered use in the most recent peak period of November through April is greater than or equal to seventy-three (73) percent of the metered use for the most recent twelve consecutive months of September through August, and whose normal annual usage is greater than 22,000 Therms but equal to or less than 100,000 Therms.

In the case of a new customer, or a customer with new gas applications, the peak percentage classification for the first year shall be that agreed upon by the Company and the Customer.

Character of Service:

Natural gas containing not less than 960 B.T.U. per cubic foot.

Distribution Service Rate:

Customer Charge:	$48.00 per 30 Day Month
Energy Charge during the months of:	
November - April	$0.4835 per Therm
May - October	$0.3900 per Therm

Other Charges for Distribution Service and Minimum Charge:

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause (LDAC), Revenue Decoupling Adjustment Clause (RDA), and Performance-Based Ratemaking (PBR) Plan filings, as in effect from time to time and on file with Massachusetts Department of Public Utilities (Department). The minimum charge per month shall be the Customer Charge.

Supply Charges:

If the customer purchases its gas from a third party, supply charges will be as agreed upon between the customer and the third party supplier (and may be billed directly by the third party supplier or through the Company as a separate item in the Company's bills to the customer). If the customer does not purchase its gas from a third party, it will receive Default Service from the Company and will pay the costs set forth in the Company's Cost of Gas Adjustment Clause (CGAC) in effect from time to time and on file with the Department.

Terms and Conditions of Distribution Service:

As in effect from time to time.

Low Load Factor General Service Rate – Medium
Essex Division
Classification No. G-42E

Farm Discount:

A customer who is certified annually by the Department of Food and Agriculture as being eligible for the Farm Discount Program will receive a discount in the amount of ten (10) percent from the charges set forth in this rate schedule.

Low Load Factor General Service Rate – Large
Boston Division
Classification No. G-43B

Availability:

Available to commercial, industrial, and institutional customers located in the Boston Division service territory whose metered use in the most recent peak period of November through April is greater than or equal to seventy (70) percent of the metered use for the most recent twelve consecutive months of September through August, and whose maximum hourly meter capacity is between 1,501 and 12,000 cubic feet per hour.

In the case of a new customer, or a customer with new gas applications, the peak percentage classification for the first year shall be that agreed upon by the Company and the Customer.

Character of Service:

Natural gas containing not less than 960 B.T.U. per cubic foot.

Distribution Service Rate:

Customer Charge:	$125.00 per 30 Day Month
Energy Charge during the months of:	
November - April	$0.4340 per Therm
May - October	$0.3777 per Therm

Other Charges for Distribution Service and Minimum Charge:

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause (LDAC), Revenue Decoupling Adjustment Clause (RDA), and Performance-Based Ratemaking (PBR) Plan filings, as in effect from time to time and on file with Massachusetts Department of Public Utilities (Department). The minimum charge per month shall be the Customer Charge.

Supply Charges:

If the customer purchases its gas from a third party, supply charges will be as agreed upon between the customer and the third party supplier (and may be billed directly by the third party supplier or through the Company as a separate item in the Company's bills to the customer). If the customer does not purchase its gas from a third party, it will receive Default Service from the Company and will pay the costs set forth in the Company's Cost of Gas Adjustment Clause (CGAC) in effect from time to time and on file with the Department.

Terms and Conditions of Distribution Service:

As in effect from time to time.

Low Load Factor General Service Rate – Large
Boston Division
Classification No. G-43B

Farm Discount:

A customer who is certified annually by the Department of Food and Agriculture as being eligible for the Farm Discount Program will receive a discount in the amount of ten (10) percent from the charges set forth in this rate schedule.

Low Load Factor General Service Rate – Large
Colonial Division
Classification No. G-43C

Availability:

Available to commercial, industrial, and institutional customers located in the Colonial Division service territory whose metered use in the most recent peak period of November through April is greater than or equal to seventy- two percent (72%) of the metered use for the most recent twelve consecutive months of September through August, and whose metered annual gas usage is greater than 100,000 Therms (billing units).

In the case of a new customer, or a customer with new gas applications, the peak percentage classification for the first year shall be that agreed upon by the Company and the Customer.

Character of Service:

Natural gas containing not less than 960 B.T.U. per cubic foot.

Distribution Service Rate:

Customer Charge	$125.00 per 30 Day Month
Energy Charge during the billing months of:	
November – April	$0.3518 per Therm
May – October	$0.2269 per Therm

Other Charges for Distribution Service and Minimum Charge:

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause (LDAC), Revenue Decoupling Adjustment Clause (RDA), and Performance-Based Ratemaking (PBR) Plan filings, as in effect from time to time and on file with the Massachusetts Department of Public Utilities (Department). The minimum charge per month shall be the Customer Charge.

Supply Charges:

If the customer purchases its gas from a third party, supply charges will be as agreed upon between the customer and the third party supplier (and may be billed directly by the third party supplier or through the Company as a separate item in the Company's bills to the customer). If the customer does not purchase its gas from a third party, it will receive Default Service from the Company and will pay the costs set forth in the Company's Cost of Gas Adjustment Clause (CGAC) in effect from time to time and on file with the Department.

Low Load Factor General Service Rate – Large
Colonial Division
Classification No. G-43C

Terms and Conditions of Distribution Service:

As in effect from time to time.

Farm Discount:

A customer who is certified annually by the Department of Food and Agriculture as being eligible for the Farm Discount Program will receive a discount in the amount of ten (10) percent from the charges set forth in this rate schedule.

Low Load Factor General Service Rate – Large
Essex Division
Classification No. G-43E

Availability:

Available to commercial, industrial, and institutional customers located in the former Essex service territory whose metered use in the most recent peak period of November through April is greater than or equal to seventy-three (73) percent of the metered use for the most recent twelve consecutive months of September through August, and-whose normal annual usage is greater than 100,000 Therms.

In the case of a new customer, or a customer with new gas applications, the peak percentage classification for the first year shall be that agreed upon by the Company and the Customer.

Character of Service:

Natural gas containing not less than 960 B.T.U. per cubic foot.

Distribution Service Rate:

Customer Charge:	$125.00 per 30 Day Month
Energy Charge during the months of:	
November - April	$0.4340 per Therm
May - October	$0.3777 per Therm

Other Charges for Distribution Service and Minimum Charge:

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause (LDAC), Revenue Decoupling Adjustment Clause (RDA), and Performance-Based Ratemaking (PBR) Plan filings, as in effect from time to time and on file with Massachusetts Department of Public Utilities (Department). The minimum charge per month shall be the Customer Charge.

Supply Charges:

If the customer purchases its gas from a third party, supply charges will be as agreed upon between the customer and the third party supplier (and may be billed directly by the third party supplier or through the Company as a separate item in the Company's bills to the customer). If the customer does not purchase its gas from a third party, it will receive Default Service from the Company and will pay the costs set forth in the Company's Cost of Gas Adjustment Clause (CGAC) in effect from time to time and on file with the M.D.P.U.

Terms and Conditions of Distribution Service:

As in effect from time to time.

Low Load Factor General Service Rate – Large
Essex Division
Classification No. G-43E

Farm Discount:

A customer who is certified annually by the Department of Food and Agriculture as being eligible for the Farm Discount Program will receive a discount in the amount of ten (10) percent from the charges set forth in this rate schedule.

Low Load Factor General Service Rate – Extra Large
Boston Division
Classification No. G-44B

Availability:

Available to commercial, industrial and institutional customers located in the Boston Division service territory whose metered use in the most recent peak period of November through April is greater than or equal to seventy (70) percent of the metered use for the most recent twelve consecutive months of September through August, and whose maximum hourly meter capacity is greater than 12,000 cubic feet per hour.

In the case of a new customer, or a customer with new gas applications, the peak percentage classification for the first year shall be that agreed upon by the Company and the Customer.

Character of Service:

Natural gas containing not less than 960 B.T.U. per cubic foot.

Distribution Service Rate:

Customer Charge:	$553.00 per 30 Day Month
Reservation Charge - $/MDCQ Therm Per Month:	
November - April	$6.3229 per Peak MDCQ Therm
May - October	$2.1938 per Off-Peak MDCQ Therm

Determination of Maximum Daily Contract Quantity (MDCQ):

Each season's MDCQ is determined annually. The calculation uses the Customer's billing history for the previous peak and off-peak seasons. The number of therms used in each billing period is adjusted to a 30-day basis. The highest monthly usage for each season is then divided by 21 to determine each season's MDCQ. Upon the written request of the Customer, the Company may adjust the Customer's seasonal MDCQ once between the seasonal determination of MDCQs if the Customer's natural gas-fired equipment has changed such that estimated metered use will increase or decrease by at least 25 percent. The Company shall require documentation of equipment changes before a mid-year adjustment to the MDCQ is made. Any adjustment to the MDCQ shall not be retroactive.

Other Charges for Distribution Service and Minimum Charge:

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause (LDAC), Revenue Decoupling Adjustment Clause (RDA), and Performance-Based Ratemaking (PBR) Plan filings, as in effect from time to time and on file with Massachusetts Department of Public Utilities (Department). The minimum charge per month shall be the Customer Charge.

Low Load Factor General Service Rate – Extra Large
Boston Division
Classification No. G-44B

Supply Charges:

If the customer purchases its gas from a third party, supply charges will be as agreed upon between the customer and the third party supplier (and may be billed directly by the third party supplier or through the Company as a separate item in the Company's bills to the customer). If the customer does not purchase its gas from a third party, it will receive Default Service from the Company and will pay the costs set forth in the Company's Cost of Gas Adjustment Clause (CGAC) in effect from time to time and on file with the Department.

Terms and Conditions of Distribution Service:

As in effect from time to time.

Farm Discount:

A customer who is certified annually by the Department of Food and Agriculture as being eligible for the Farm Discount Program will receive a discount in the amount of ten (10) percent from the charges set forth in this rate schedule.

High Load Factor General Service Rate – Small
Boston Division
Classification No. G-51B

Availability:

Available to commercial, industrial, and institutional customers located in the Boston Division service territory whose metered use in the most recent peak period of November through April is less than seventy (70) percent of the metered use for the most recent twelve consecutive months of September through August, and whose maximum hourly meter capacity is less than or equal to 500 cubic feet per hour.

In the case of a new customer, or a customer with new gas applications, the peak percentage classification for the first year shall be that agreed upon by the Company and the Customer.

Character of Service:

Natural gas containing not less than 960 B.T.U. per cubic foot.

Distribution Service Rate:

Customer Charge:	$26.00 per 30 Day Month
Energy Charge during the months of:	
November - April	$0.2362 per Therm
May - October	$0.2159 per Therm

Other Charges for Distribution Service and Minimum Charge:

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause (LDAC), Revenue Decoupling Adjustment Clause (RDA), and Performance-Based Ratemaking (PBR) Plan filings, as in effect from time to time and on file with Massachusetts Department of Public Utilities (Department). The minimum charge per month shall be the Customer Charge

Supply Charges:

If the customer purchases its gas from a third party, supply charges will be as agreed upon between the customer and the third party supplier (and may be billed directly by the third party supplier or through the Company as a separate item in the Company's bills to the customer). If the customer does not purchase its gas from a third party, it will receive Default Service from the Company and will pay the costs set forth in the Company's Cost of Gas Adjustment Clause (CGAC) in effect from time to time and on file with the Department.

High Load Factor General Service Rate – Small
Boston Division
Classification No. G-51B

Terms and Conditions of Distribution Service:

As in effect from time to time.

Farm Discount:

A customer who is certified annually by the Department of Food and Agriculture as being eligible for the Farm Discount Program will receive a discount in the amount of ten (10) percent from the charges set forth in this rate schedule.

High Load Factor General Service Rate – Small
Colonial Division
Classification No. G-51C

Availability:

Available to commercial, industrial, and institutional customers located in the Colonial Division service territory whose metered use in the most recent peak period of November through April is less than seventy-two percent (72%) of the metered use for the most recent twelve consecutive months of September through August, and whose metered annual gas usage is 20,000 Therms (billing units) or less.

In the case of a new customer, or a customer with new gas applications, the peak percentage classification for the first year shall be that agreed upon by the Company and the Customer.

Character of Service:

Natural gas containing not less than 960 B.T.U. per cubic foot.

Distribution Service Rate:

Customer Charge	$19.00 per 30 Day Month
Energy Charge during the billing months of:	
November – April	$0.3272 per Therm
May – October	$0.2990 per Therm

Other Charges for Distribution Service and Minimum Charge:

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause (LDAC), Revenue Decoupling Adjustment (RDA), and Performance-Based Ratemaking (PBR) Plan filings, as in effect from time to time and on file with the Massachusetts Department of Public Utilities (Department). The minimum charge per month shall be the Customer Charge.

Supply Charges:

If the customer purchases its gas from a third party, supply charges will be as agreed upon between the customer and the third party supplier (and may be billed directly by the third party supplier or through the Company as a separate item in the Company's bills to the customer). If the customer does not purchase its gas from a third party, it will receive Default Service from the Company and will pay the costs set forth in the Company's Cost of Gas Adjustment Clause (CGAC) in effect from time to time and on file with the Department.

High Load Factor General Service Rate – Small
Colonial Division
Classification No. G-51C

Terms and Conditions of Distribution Service:

As in effect from time to time.

Farm Discount:

A customer who is certified annually by the Department of Food and Agriculture as being eligible for the Farm Discount Program will receive a discount in the amount of ten (10) percent from the charges set forth in this rate schedule.

High Load Factor General Service Rate – Small
Essex Division
Classification No. G-51E

Availability:

Available to commercial, industrial, and institutional customers located in the former Essex service territory whose metered use in the most recent peak period of November through April is less than seventy-three (73) percent of the metered use for the most recent twelve consecutive months of September through August, and whose normal annual usage is 45,000 Therms or less.

In the case of a new customer, or a customer with new gas applications, the peak percentage classification for the first year shall be that agreed upon by the Company and the Customer.

Character of Service:

Natural gas containing not less than 960 B.T.U. per cubic foot.

Distribution Service Rate:

Customer Charge:	$26.00 per 30 Day Month
Energy Charge during the months of:	
November - April	$0.3285 per Therm
May - October	$0.2796 per Therm

Other Charges for Distribution Service and Minimum Charge:

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause (LDAC), Revenue Decoupling Adjustment Clause (RDA), and Performance-Based Ratemaking (PBR) Plan filings, as in effect from time to time and on file with Massachusetts Department of Public Utilities (Department). The minimum charge per month shall be the Customer Charge.

Supply Charges:

If the customer purchases its gas from a third party, supply charges will be as agreed upon between the customer and the third party supplier (and may be billed directly by the third party supplier or through the Company as a separate item in the Company's bills to the customer). If the customer does not purchase its gas from a third party, it will receive Default Service from the Company and will pay the costs set forth in the Company's Cost of Gas Adjustment Clause (CGAC) in effect from time to time and on file with the Department.

Terms and Conditions of Distribution Service:

As in effect from time to time.

High Load Factor General Service Rate – Small
Essex Division
Classification No. G-51E

Farm Discount:

A customer who is certified annually by the Department of Food and Agriculture as being eligible for the Farm Discount Program will receive a discount in the amount of ten (10) percent from the charges set forth in this rate schedule.

High Load Factor General Service Rate – Medium
Boston Division
Classification No. G-52B

Availability:

Available to commercial, industrial, and institutional customers located in the Boston Division service territory whose metered use in the most recent peak period of November through April is less than seventy (70) percent of the metered use for the most recent twelve consecutive months of September through August, and whose maximum hourly meter capacity is between 501 and 1,500 cubic feet per hour.

In the case of a new customer, or a customer with new gas applications, the peak percentage classification for the first year shall be that agreed upon by the Company and the Customer.

Character of Service:

Natural gas containing not less than 960 B.T.U. per cubic foot.

Distribution Service Rate:

Customer Charge:	$48.00 per 30 Day Month
Energy Charge during the months of:	
November - April	$0.2355 per Therm
May - October	$0.2183 per Therm

Other Charges for Distribution Service and Minimum Charge:

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause (LDAC), Revenue Decoupling Adjustment Clause (RDA), and Performance-Based Ratemaking (PBR) Plan filings, as in effect from time to time and on file with Massachusetts Department of Public Utilities (Department). The minimum charge per month shall be the Customer Charge.

Supply Charges:

If the customer purchases its gas from a third party, supply charges will be as agreed upon between the customer and the third party supplier (and may be billed directly by the third party supplier or through the Company as a separate item in the Company's bills to the customer). If the customer does not purchase its gas from a third party, it will receive Default Service from the Company and will pay the costs set forth in the Company's Cost of Gas Adjustment Clause (CGAC) in effect from time to time and on file with the Department.

Terms and Conditions of Distribution Service:

As in effect from time to time.

High Load Factor General Service Rate – Medium
Boston Division
Classification No. G-52B

Farm Discount:

A customer who is certified annually by the Department of Food and Agriculture as being eligible for the Farm Discount Program will receive a discount in the amount of ten (10) percent from the charges set forth in this rate schedule.

High Load Factor General Service Rate – Medium
Colonial Division
Classification No. G-52C

Availability:

Available to commercial, industrial, and institutional customers located in the Colonial Division service territory whose metered use in the most recent peak period of November through April is less than seventy- two percent (72%) of the metered use for the most recent twelve consecutive months of September through August, and whose metered annual gas usage is greater than 20,000 and less than or equal to 100,000 Therms (billing units).

In the case of a new customer, or a customer with new gas applications, the peak percentage classification for the first year shall be that agreed upon by the Company and the Customer.

Character of Service:

Natural gas containing not less than 960 B.T.U. per cubic foot.

Distribution Service Rate:

Customer Charge	$48.00 per 30 Day Month
Energy Charge during the billing months of:	
November – April	$0.3057 per Therm
May – October	$0.2791 per Therm

Other Charges for Distribution Service and Minimum Charge:

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause (LDAC), Revenue Decoupling Adjustment Clause (RDA), and Performance-Based Ratemaking (PBR) Plan filings, as in effect from time to time and on file with the Massachusetts Department of Public Utilities (Department). The minimum charge per month shall be the Customer Charge.

Supply Charges:

If the customer purchases its gas from a third party, supply charges will be as agreed upon between the customer and the third party supplier (and may be billed directly by the third party supplier or through the Company as a separate item in the Company's bills to the customer). If the customer does not purchase its gas from a third party, it will receive Default Service from the Company and will pay the costs set forth in the Company's Cost of Gas Adjustment Clause (CGAC) in effect from time to time and on file with the Department.

High Load Factor General Service Rate – Medium
Colonial Division
Classification No. G-52C

Terms and Conditions of Distribution Service:

As in effect from time to time.

Farm Discount:

A customer who is certified annually by the Department of Food and Agriculture as being eligible for the Farm Discount Program will receive a discount in the amount of ten (10) percent from the charges set forth in this rate schedule.

High Load Factor General Service Rate – Medium
Essex Division
Classification No. G-52E

Availability:

Available to commercial, industrial, and institutional customers located in the former Essex service territory whose metered use in the most recent peak period of November through April is less than seventy-three (73) percent of the metered use for the most recent twelve consecutive months of September through August, and whose normal annual usage is greater than 45,000 Therms and less than or equal to 180,000 Therms.

In the case of a new customer, or a customer with new gas applications, the peak percentage classification for the first year shall be that agreed upon by the Company and the Customer.

Character of Service:

Natural gas containing not less than 960 B.T.U. per cubic foot.

Distribution Service Rate:

Customer Charge:	$48.00 per 30 Day Month
Energy Charge during the months of:	
November - April	$0.2294 per Therm
May - October	$0.1824 per Therm

Other Charges for Distribution Service and Minimum Charge:

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause (LDAC), Revenue Decoupling Adjustment Clause (RDA), and Performance-Based Ratemaking (PBR) Plan filings, as in effect from time to time and on file with Massachusetts Department of Public Utilities (Department). The minimum charge per month shall be the Customer Charge.

Supply Charges:

If the customer purchases its gas from a third party, supply charges will be as agreed upon between the customer and the third party supplier (and may be billed directly by the third party supplier or through the Company as a separate item in the Company's bills to the customer). If the customer does not purchase its gas from a third party, it will receive Default Service from the Company and will pay the costs set forth in the Company's Cost of Gas Adjustment Clause (CGAC) in effect from time to time and on file with the Department.

Terms and Conditions of Distribution Service:

As in effect from time to time.

High Load Factor General Service Rate – Medium
Essex Division
Classification No. G-52E

Farm Discount:

A customer who is certified annually by the Department of Food and Agriculture as being eligible for the Farm Discount Program will receive a discount in the amount of ten (10) percent from the charges set forth in this rate schedule.

High Load Factor General Service Rate – Large
Boston Division
Classification No. G-53B

Availability:

Available to commercial, industrial, and institutional customers located in the Boston Division service territory whose metered use in the most recent peak period of November through April is less than seventy (70) percent of the metered use for the most recent twelve consecutive months of September through August, and whose maximum hourly meter capacity is between 1,501 and 12,000 cubic feet per hour.

In the case of a new customer, or a customer with new gas applications, the peak percentage classification for the first year shall be that agreed upon by the Company and the Customer.

Character of Service:

Natural gas containing not less than 960 B.T.U. per cubic foot.

Distribution Service Rate:

Customer Charge:	$125.00 per 30 Day Month
Energy Charge during the months of:	
November - April	$0.2017 per Therm
May - October	$0.1872 per Therm

Other Charges for Distribution Service and Minimum Charge:

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause (LDAC), Revenue Decoupling Adjustment Clause (RDA), and Performance-Based Ratemaking (PBR) Plan filings, as in effect from time to time and on file with Massachusetts Department of Public Utilities (Department). The minimum charge per month shall be the Customer Charge.

Supply Charges:

If the customer purchases its gas from a third party, supply charges will be as agreed upon between the customer and the third party supplier (and may be billed directly by the third party supplier or through the Company as a separate item in the Company's bills to the customer). If the customer does not purchase its gas from a third party, it will receive Default Service from the Company and will pay the costs set forth in the Company's Cost of Gas Adjustment Clause (CGAC) in effect from time to time and on file with the Department.

Terms and Conditions of Distribution Service:

As in effect from time to time.

High Load Factor General Service Rate – Large
Boston Division
Classification No. G-53B

Farm Discount:

A customer who is certified annually by the Department of Food and Agriculture as being eligible for the Farm Discount Program will receive a discount in the amount of ten (10) percent from the charges set forth in this rate schedule.

High Load Factor General Service Rate – Large
Colonial Division
Classification No. G-53C

Availability:

Available to commercial, industrial, and institutional customers located in the Colonial Division service territory whose metered use in the most recent peak period of November through April is less than seventy-two percent (72%) of the metered use for the most recent twelve consecutive months of September through August, and whose metered annual gas usage is greater than 100,000 Therms (billing units).

In the case of a new customer, or a customer with new gas applications, the peak percentage classification for the first year shall be that agreed upon by the Company and the Customer.

Character of Service:

Natural gas containing not less than 960 B.T.U. per cubic foot.

Distribution Service Rate:

Customer Charge	$125.00 per 30 Day Month
Energy Charge during the billing months of:	
November – April	$0.1666 per Therm
May – October	$0.1533 per Therm

Other Charges for Distribution Service and Minimum Charge:

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause (LDAC), Revenue Decoupling Adjustment Clause (RDA), and Performance-Based Ratemaking (PBR) Plan filings, as in effect from time to time and on file with the Massachusetts Department of Public Utilities (Department). The minimum charge per month shall be the Customer Charge.

Supply Charges:

If the customer purchases its gas from a third party, supply charges will be as agreed upon between the customer and the third party supplier (and may be billed directly by the third party supplier or through the Company as a separate item in the Company's bills to the customer). If the customer does not purchase its gas from a third party, it will receive Default Service from the Company and will pay the costs set forth in the Company's Cost of Gas Adjustment Clause (CGAC) in effect from time to time and on file with the Department.

High Load Factor General Service Rate – Large
Colonial Division
Classification No. G-53C

Terms and Conditions of Distribution Service:

As in effect from time to time.

Farm Discount:

A customer who is certified annually by the Department of Food and Agriculture as being eligible for the Farm Discount Program will receive a discount in the amount of ten (10) percent from the charges set forth in this rate schedule.

High Load Factor General Service Rate – Large
Essex Division
Classification No. G-53E

Availability:

Available to commercial, industrial, and institutional customers located in the former Essex service territory whose metered use in the most recent peak period of November through April is less than seventy-three (73) percent of the metered use for the most recent twelve consecutive months of September through August, and whose normal annual usage is greater than 180,000 Therms.

In the case of a new customer, or a customer with new gas applications, the peak percentage classification for the first year shall be that agreed upon by the Company and the Customer.

Character of Service:

Natural gas containing not less than 960 B.T.U. per cubic foot.

Distribution Service Rate:

Customer Charge:	$553.00 per 30 Day Month
Reservation Charge - $/MDCQ Therm Per Month:	
November - April	$4.6450 per Peak MDCQ Therm
May - October	$1.6714 per Off Peak MDCQ Therm

Determination of Maximum Daily Contract Quantity (MDCQ):

Each season's MDCQ is redetermined annually. The calculation uses the Customer's billing history for the previous peak and off-peak seasons. The number of therms used in each billing period is adjusted to a 30-day basis. The highest monthly usage for each season is then divided by 21 to determine each season's MDCQ. Upon the written request of the Customer, the Company may adjust the Customer's seasonal MDCQ once between the seasonal determination of MDCQs if the Customer's natural gas-fired equipment has changed such that estimated metered use will increase or decrease by at least twenty-five (25) percent. The Company shall require documentation of equipment changes before a mid-year adjustment to the MDCQ is made. Any adjustment to the MDCQ shall not be retroactive.

Other Charges for Distribution Service and Minimum Charge:

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause (LDAC), Revenue Decoupling Adjustment Clause (RDA), and Performance-Based Ratemaking (PBR) Plan filings, as in effect from time to time and on file with Massachusetts Department of Public Utilities (Department). The minimum charge per month shall be the Customer Charge.

High Load Factor General Service Rate – Large
Essex Division
Classification No. G-53E

Supply Charges:

If the customer purchases its gas from a third party, supply charges will be as agreed upon between the customer and the third party supplier (and may be billed directly by the third party supplier or through the Company as a separate item in the Company's bills to the customer). If the customer does not purchase its gas from a third party, it will receive Default Service from the Company and will pay the costs set forth in the Company's Cost of Gas Adjustment Clause (CGAC) in effect from time to time and on file with the Department.

Terms and Conditions of Distribution Service:

As in effect from time to time.

Farm Discount:

A customer who is certified annually by the Department of Food and Agriculture as being eligible for the Farm Discount Program will receive a discount in the amount of ten (10) percent from the charges set forth in this rate schedule.

High Load Factor General Service Rate – Extra Large
Boston Division
Classification No. G-54B

Availability:

Available to commercial, industrial, and institutional customers located in the Boston Division service territory whose metered use in the most recent peak period of November through April is less than seventy (70) percent of the metered use for the most recent twelve consecutive months of September through August, and whose maximum hourly meter capacity is greater than 12,000 cubic feet per hour.

In the case of a new customer, or a customer with new gas applications, the peak percentage classification for the first year shall be that agreed upon by the Company and the Customer.

Character of Service:

Natural gas containing not less than 960 B.T.U. per cubic foot.

Distribution Service Rate:

Customer Charge:	$553.00 per 30 Day Month
Reservation Charge - $/MDCQ Therm Per Month:	
November - April	$4.6450 per Peak MDCQ Therm
May - October	$1.6714 per Off-Peak MDCQ Therm

Determination of Maximum Daily Contract Quantity (MDCQ):

Each season's MDCQ is redetermined annually. The calculation uses the Customer's billing history for the previous peak and off-peak seasons. The number of therms used in each billing period is adjusted to a 30-day basis. The highest monthly usage for each season is then divided by 21 to determine each season's MDCQ. Upon the written request of the Customer, the Company may adjust the Customer's seasonal MDCQ once between the seasonal determination of MDCQs if the Customer's natural gas-fired equipment has changed such that estimated metered use will increase or decrease by at least twenty-five (25) percent. The Company shall require documentation of equipment changes before a mid-year adjustment to the MDCQ is made. Any adjustment to the MDCQ shall not be retroactive.

Other Charges for Distribution Service and Minimum Charge:

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause (LDAC), Revenue Decoupling Adjustment Clause (RDA), and Performance-Based Ratemaking (PBR) Plan filings, as in effect from time to time and on file with Massachusetts Department of Public Utilities (Department). The minimum charge per month shall be the Customer Charge.

High Load Factor General Service Rate – Extra Large
Boston Division
Classification No. G-54B

Supply Charges:

If the customer purchases its gas from a third party, supply charges will be as agreed upon between the customer and the third party supplier (and may be billed directly by the third party supplier or through the Company as a separate item in the Company's bills to the customer). If the customer does not purchase its gas from a third party, it will receive Default Service from the Company and will pay the costs set forth in the Company's Cost of Gas Adjustment Clause (CGAC) in effect from time to time and on file with the Department.

Terms and Conditions of Distribution Service:

As in effect from time to time.

Farm Discount:

A customer who is certified annually by the Department of Food and Agriculture as being eligible for the Farm Discount Program will receive a discount in the amount of ten (10) percent from the charges set forth in this rate schedule.

Street Lighting Rate
Boston Division
Classification No. G-7B

Availability:

Available to any customer located in the Boston Division service territory for gas used for the purpose of street lighting.

Rate: Bills to be rendered monthly.

Fixed Charge Per Lamp:	$1.31 per 30 Day Month
Volumetric/Hourly Conversion Factor:	
November - April	0.0424 per therm/hour
May - October	0.0424 per therm/hour

Lighting and Extinguishing:

The customer shall furnish the Company with the schedule of burning hours of lamps which the customer will maintain. Any excess burning hour of lamps, due to the failure of the customer to light and extinguish all lamps within fifteen minutes of the times fixed such schedule, shall be subject to the running charge.

The number of lamps in service during each calendar year shall be furnished to the Company by the customer on or before the third day of the succeeding month.

Allowance for Inadequate Supply of Gas:

Provided written notice of an inadequate supply of gas to any lamp is received by the Company, a deduction from the monthly charges shall be made in the amount of one half cent ($0.005) per hour for each burning hour during which such inadequate supply of gas continues, except that no such deduction shall be made for the first twenty-four (24) hours after receipt of such notice and no such deduction shall be made for failure of the Company to deliver an adequate supply of gas because of certain frost stoppages in the service pipe which shall be service by the customer or his agent in accordance with the following paragraph.

Service:

The Company will, except when prevented by circumstances beyond its control, furnish a continuous adequate supply of gas to each lighting fixture, except that any frost stoppage in a service pipe which can be cleared by the use of alcohol (to be supplied by the Company) will be served by the customer or the customer's agent. The lamp, post, burner, pressure regulator and other parts of the gas lamp (except the service pipe to the fixture) are the property of the customer, the customer's principal or agent, and maintenance or repair work performed by the Company (except to the service pipe in the lighting fixture) shall be at the expense of the customer, and any change in location of an installed lamp will be made only at the expense of the customer.

Street Lighting Rate
Boston Division
Classification No. G-7B

Installation and Discontinuance:

Lamp posts are installed by the Company at the expense of the customer for use at this rate only on the basis of permanent service. A customer may discontinue any lamp or lamps by written notice to the Company, but the customer will be required to pay the entire expense in connection with such discontinuance including the cost of materials, labor, trucking and the restoration of the street or sidewalk surface and to assume all liability arising after such removal.

Other Charges for Distribution Service and Minimum Charge:

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause (LDAC) and Performance-Based Ratemaking (PBR) Plan filings, as in effect from time to time and on file with Massachusetts Department of Public Utilities (Department). The Company will convert the volumetric Local Distribution Adjustment Factor to an hourly rate in accordance with the Volumetric/Hourly Conversion Factor above. The minimum charge per month shall be the Fixed Charge per lamp.

Supply Charges:

If the customer purchases its gas from a third party, supply charges will be as agreed upon between the customer and the third party supplier (and may be billed directly by the third party supplier or through the Company as a separate item in the Company's bills to the customer). If the customer does not purchase its gas from a third party, it will receive Default Service from the Company and will pay the Company's Cost of Gas Adjustment Clause (CGAC) in effect from time to time and on file with the Department. The Company will convert the volumetric Gas Adjustment Factor to an hourly rate in accordance with the Volumetric/Hourly Conversion Factor above.

Terms and Conditions of Distribution Service:

As in effect from time to time.

Outdoor Gas Lighting
Boston Division
Classification No. G-17B

Availability:

Available to all customers located in the Boston Division service territory for outdoor gas lighting where a standard gas light is attached to the Company's existing distribution system and when it is not feasible to meter gas for such lighting along with other gas used on the premises and bill the same under the rate in effect for all other service. All such installations shall be on private property.

Character of Service:

Unmetered gas service for outdoor lighting. Natural gas containing not less than 960 B.T.U. per cubic foot.

Rate: Applicable to each gas light:

Fixed Charge Per Lamp: $11.39 per 30 day month

Minimum Monthly Charge:

The sum of the Rate and the Local Distribution Adjustment Factor, as calculated below. For Default Service customers, the minimum charge will also include the Gas Adjustment Factor as calculated below.

Other Charges for Distribution Service and Minimum Charge:

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause (LDAC) and Performance-Based Ratemaking (PBR) Plan filings, as in effect from time to time and on file with Massachusetts Department of Public Utilities (Department). The customer will pay $0.22 for each $0.01 per therm of the Company's Local Distribution Adjustment Factor.

Supply Charges:

If the customer purchases its gas from a third party, supply charges will be as agreed upon between the customer and the third party supplier (and may be billed directly by the third party supplier or through the Company as a separate item in the Company's bills to the customer). If the customer does not purchase its gas from a third party, it will receive Default Service from the Company and will pay $0.22 for each $0.01 per therm of the Company's Cost of Gas Adjustment Factor in effect from time to time and on file with the Department.

Terms and Conditions of Distribution Service:

As in effect from time to time.

Outdoor Gas Lighting
Boston Division
Classification No. G-17B

Special Provisions:

The customer shall own, install, and maintain the post, lamp fixture, and mantles.

Outdoor Gas Lighting
Colonial Division
Classification No. G-17C

Availability:

Available to all customers for outdoor gas lighting located in the Colonial Division service territory where a standard gas light is attached to the Company's existing distribution system and when it is not feasible to meter gas for such lighting along with other gas used on the premises and bill the same under the rate in effect for all other service. All such installations shall be on private property.

Character of Service:

Unmetered gas service for outdoor lighting. Natural gas containing not less than 960 B.T.U. per cubic foot.

Rate: Applicable to each gas light:

Fixed Charge Per Lamp: $1.80 per 30 day month

Minimum Monthly Charge:

The sum of the Rate and the Local Distribution Adjustment Factor, as calculated below. For Default Service customers, the minimum charge will also include the Cost of Gas Adjustment Factor as calculated below.

Other Charges for Distribution Service and Minimum Charge:

The customer must also pay such charges and adjustments as are set forth in the Company's Local Distribution Adjustment Clause (LDAC) Performance-Based Ratemaking (PBR) Plan filings, as in effect from time to time and on file with the Massachusetts Department of Public Utilities (Department). The customer will pay $0.22 for each $0.01 per therm of the Company's Local Distribution Adjustment Factor.

Supply Charges:

If the customer purchases its gas from a third party, supply charges will be as agreed upon between the customer and the third party supplier (and may be billed directly by the third party supplier or through the Company as a separate item in the Company's bills to the customer). If the customer does not purchase its gas from a third party, it will receive Default Service from the Company and will pay $0.22 for each $0.01 per therm of the Company's Cost of Gas Adjustment Factor in effect from time to time and on file with the Department.

Outdoor Gas Lighting
Colonial Division
Classification No. G-17C

Terms and Conditions of Distribution Service:

As in effect from time to time.

Special Provisions:

The Customer shall own, install and maintain the post, lamp fixture and mantles.

RESIDENTIAL AUTOMATIC METER READING OPT-OUT PROVISION

Availability

Service under this provision is available to residential customers receiving metered retail delivery service under the Company's Rate R-1, Residential Non-Heating; Rate R-2, Residential Non-Heating Low Income; Rate R-3, Residential Heating; and Rate R-4, Residential Heating Low Income.

Description of Services

Unless otherwise determined by the Company, all residential premises shall be equipped with a meter that employs Automatic Meter Reading ("AMR") technology utilizing radio frequency transmitters to allow the Company to obtain meter readings remotely. However, residential customers may choose to "opt-out" by having their AMR meter replaced with a non-AMR meter. At the customer's request, the Company shall exchange the existing AMR gas meter at the customer's location and install a non-AMR meter for the purpose of billing gas service to the customer. Upon receipt of the Customer's request, the Company shall use its best efforts to exchange meters as soon as possible after receiving the request. However, the Company reserves the right to flexibility in scheduling the meter exchange in an appropriate manner based on resource availability. Customers who choose to opt-out will be charged an initial fee for the removal of the existing AMR meter and the installation of the non-AMR meter, pursuant to the Schedule of Charges below. Customers who choose to opt-out will also be charged a monthly meter reading fee for the non-AMR meter, pursuant to the Schedule of Charges below. The Company, at its option, may choose to read the non-AMR meter less frequently than once per month. In that case, or if the Company is unable for any reason to read the meter on the regularly scheduled monthly read date, the Company shall make a reasonable estimate of the consumption of gas during those months when the meter is not read, based on available data, and such estimated bills shall be payable as rendered. The monthly meter reading fee will be charged on estimated bills. The Company will not assess any fees until after the Company has installed the non-AMR meter.

Any opt-out customer who subsequently wishes to have an AMR meter re-installed will be charged a "re-installation fee" pursuant to the Schedule of Charges below. The re-installation fee will be charged for the removal of the non-AMR meter and the installation of an AMR meter. After an AMR meter has been re-installed, the Company will terminate billing the monthly meter reading fee.

Schedule of Charges

The AMR Opt-Out Charges are as follows:

Removal of AMR Meter/Installation of Non-AMR Meter	$66.00
Monthly Meter Reading	$25.00
Re-installation of AMR Meter	$66.00

Terms and Conditions

The Company's Terms and Conditions for Distribution Service in effect from time to time where not inconsistent with any specific provisions hereof, are a part of this tariff.

Performance-Based Ratemaking Tariff

Section

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1.0 Purpose

This Performance-Based Ratemaking ("PBR") Tariff provides for a PBR Plan consisting of a PBR Mechanism (or "PBRM") that allows Boston Gas Company d/b/a National Grid (the "Company"), subject to the jurisdiction of the Department of Public Utilities ("Department"), an annual adjustment to Base Rates pursuant to Sections 6.0, 7.0, 8.0, and 9.0.

The PBRM includes three components that provides for an annual adjustment to distribution rates. The three components of the PBRM are:

1. An annual adjustment to Base Rates based on a formula using the rate of input price inflation for the broad economy, less an adjustment for the relative productivity and input price levels of the gas industry, and less a consumer dividend ("PBR Adjustment").

2. An Earnings Sharing Mechanism that provides a credit to customers for customers' share of earnings above a certain threshold through a separate factor.

3. An Exogenous Event factor that allows the Company to reflect, either in Base Rates or through a separate factor, costs and cost reductions that are beyond the control of the Company, are not reflected in the GDPPI, and, because the Company is subject to a stay-out provision, are deemed appropriate to recover from or credit to customers through the PBR Mechanism.

To allow for the transition to the PBR Plan, an adjustment taking effect under the PBR Plan through the PBRM shall take place through separate adjustment to Base Rates at the start of the PBR Year beginning October 2022 that recovers the revenue requirement on all capital investment recorded as "in-service" during the period April 2020 through December 2020 pursuant to Section 7.0, excluding capital recovered through the Company's Gas System Enhancement Program ("GSEP") Plan filings and investments in the Company's Liquified Natural Gas ("LNG") facilities.

2.0 Term of PBR Plan

The PBR Plan shall operate for a five-year term starting October 1, 2021. The first annual adjustment pursuant to the PBRM of the PBR Plan shall be effective October 1, 2022. Subsequent annual

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adjustments shall occur within the five-year term, with the last adjustment to the then-effective Base Rates taking effect on October 1, 2025.

3.0 Applicability

The PBRM applies an annual adjustment to the Base Rates of the Company's effective distribution rate schedules subject to the jurisdiction of the Department, as determined in accordance with the provisions contained herein.

4.0 Definitions

4.1 Allowed Return on Equity is the allowed rate of return on equity as established in the Company's most recent base distribution rate case.

4.2 Base Distribution Revenue is the distribution revenue approved for recovery through the Company's rate classes as established by the Department in its most recent base distribution rate case and as adjusted annually under the provisions of this tariff.

4.3 Base Rates are the compilation of Rate Components plus the customer charge for all the Company's rate classes.

4.4 Basis Point shall be one one-hundredth of a percentage point (one basis point = 0.01%).

4.5 Common Equity is the average of the beginning year and ending year Rate Base for the calendar year prior to the Prior Year multiplied by the Common Equity percentage approved by the Department in the Company's most recent base distribution rate case.

4.6 Consumer Dividend is the benefit to consumers of future productivity gains attributable to performance-based ratemaking for the Company's distribution service as established by the Department in the Company's most recent base distribution rate case.

4.7 Distribution Revenue Allocator refers to the allocation factors for each Rate Class Grouping derived from the Company's most recent base distribution rate case, as may be adjusted from time to time as approved by the Department, as follows:

Rate Class Groupings	Allocation
Residential Non-Heating (R-1, R-2)	2.90%
Residential Heating (R-3B, R-4B, R-3C, R-4C)	64.51%
Small C&I Low Load Factor (G-41B, G-41C, G-41E)	6.38%
Small C&I High Load Factor (G-51B, G-51C, G-51E)	1.24%
Medium C&I Low Load Factor (G-42B, G-42C, G-42E)	5.51%
Medium C&I High Load Factor (G-52B, G-52C, G-52E)	1.10%
Large C&I Low Load Factor (G-43B, G-43C, G-43E)	10.16%
Large C&I High Load Factor (G-53B, G-53C)	1.71%
Extra Large C&I Low Load Factor (G-44B)	4.06%

Extra Large C&I High Load Factor (G-54B, G-53E)	2.42%
Street Lights (G-7B)	0.01%
Gas Lights (G-17B, G-17C)	0.00%
Total	100.00%

4.8 Exogenous Events are occurrences that have a material impact on the Company and that are beyond the Company's control and are not otherwise reflected in the PBR Adjustment.

4.9 Prior Year is the annual period ending immediately prior to the PBR Year.

4.10 Rate Class Grouping is the grouping of the same rate classes that are aggregated for the purpose of allocating adjustments pursuant to the PBR Tariff.

4.11 Rate Component is the applicable energy or demand charge reflected in the Company's rate class tariffs in effect from time to time that recovers a portion of the Company's Base Distribution Revenue as established by the Department in its most recent base distribution rate case.

4.12 PBR Year is the annual period that the adjusted base distribution rates shall be effective beginning on October 1.

4.13 Return on Average Common Equity ("ROE") is the Earnings Available for Common Equity as reported in the Company's annual Earnings Reports to the Department less amounts as described in Section 9.0, divided by the average of the beginning year and ending year Common Equity for the calendar year prior to the Prior Year as approved by the Department.

4.14 X Factor is the productivity adjustment value as established by the Department in D.P.U. 20-120.

4.15 Z Factor is the sum of the cost impacts of Exogenous Events.

5.0 Annual Rate Adjustments

The annual adjustment to Base Rates for each Rate Class Grouping shall be evaluated to ensure that the revenue increase to any one rate class within a Rate Class Grouping is not more than 10 percent of that rate class's total annual normalized revenue for the calendar year, consistent with the manner by which total normalized revenue is determined in a base distribution rate case, including imputed commodity revenue for customers receiving their gas supply from third party gas suppliers. To the extent that the annual adjustment to Base Rates for any Rate Class Grouping and, by extension, any rate class, exceeds 10 percent of that rate class's total annual normalized revenue, the Company shall reallocate the amount in excess of 10 percent equitably among the other rate classes and subject to the 10 percent limitation.

In calculating Base Rates for the PBR Year beginning October 1, 2022, the Company shall add the PBR Adjustment for each Rate Class Grouping as calculated pursuant to Section 6.0 and the CAPEX Adjustment for each Rate Class Grouping as calculated pursuant to Section 7.0, and the total amount shall be reflected in the Rate Component for each rate class within each Rate Class Grouping based on weather

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normalized therm and demand billing determinants for calendar year 2020 and average number of customers during calendar year 2020.

Benchmark Revenue-Per-Customer ("RPC") targets shall be adjusted based on the change in Base Distribution Revenue and the average number of customers during 2020 and reflected in the Company's Revenue Decoupling Adjustment Clause ("RDAC"), M.D.P.U. No. 62.1, as amended from time to time. The Base Distribution Revenue and PBR Adjustment will not be subject to reconciliation except as provided for in the Company's RDAC.

6.0 Calculation of PBR Adjustment

$BASE\_REV_{(C)T} = BASE\_REV_{(C)T-1} + (PBR\_ADJ_T \times DRA_C)$

$PBR\_ADJ_T = BASE\_REVC_{T-1} \times PBR\%$

$PBR\% = (GDPPI_{T-1} - X - CD) + (ZREV_T \div BASE\_REV_{T-1})$

$X = -1.30\%$

Where:

C — Rate Class Grouping.

BASE_REV — Base Distribution Revenue as defined in Section 4.3.

PBR_ADJ — The PBR Adjustment, which shall be the PBR Year's incremental Base Distribution Revenue consisting of the adjustments associated with the application of the PBR%.

DRA — The Distribution Revenue Allocator as set forth in Section 4.7.

PBR% — The percentage change to be applied to the Prior Year Base Distribution Revenue.

GDPPI — The average annual percentage change in the United States Gross Domestic Product - Price Index for the four most recent quarterly reporting periods prior to the first quarter of the calendar year in which the Rate Components reflecting the PBR Year's PBR Adjustment go into effect. The calculation will be performed based on the most recently available data published by the United States Department of Commerce at the time of the PBR filing.

X — The productivity or X Factor, which shall be negative 1.30 percent, as established by the Department in the Company's most recent base distribution rate case.

CD — Consumer dividend, which shall be 0.30 percent as established by the Department in the Company's most recent base distribution rate case.

ZREV — The sum of cost impacts of all Exogenous Events, positive or negative, as provided for in Section 8.0.

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T The PBR Year.

T-1 The Prior Year.

7.0 Transition to PBR Plan

7.1 Calculation of CAPEX Adjustment

The Company shall adjust Base Rates effective October 1, 2022 for the recovery of the annual revenue requirement on all capital investment recorded as “in-service” during the period April 2020 through December 2020 (“Capital Investment Period”) for capital investment not included for recovery in the Company’s GSEP Plan filings and the Company’s investments in LNG facilities. The Company shall reflect the December 31, 2020 balances for the components of rate base, subject to the CAPEX Formula below, to be included in Base Rates effective October 1, 2022.

$CAPEX_C$ = [(RB x PTRR) + DEPR + PTMS] x DRA_C

Where:

C Rate Class Grouping.

CAPEX The annual revenue requirement associated with all capital investments placed into service in the Capital Investment Period.

DRA The Distribution Revenue Allocator as set forth in Section 4.7.

DEPR The annual depreciation expense associated with the total capital investment in the Capital Investment Period.

PTRR The pre-tax rate of return shall be the after-tax weighted average cost of capital approved by the Department in the Company’s most recent base distribution rate case, adjusted to a pre-tax basis by using currently effective federal and state income tax rates applicable to the PBR Year.

PTMS Property taxes calculated based on the total capital investment associated with the Capital Investment Period multiplied by the property tax rate established by the Department in the Company’s most recent base distribution rate case. Property taxes will be included in CAPEX beginning in the year following the Capital Investment Period in which the capital investments were recorded as in-service at 50% of the annual property tax amount for the first year. In the subsequent year, CAPEX will reflect a full year of property taxes.

RB Rate Base at December 31, 2020 associated with total capital investment for the Capital Investment Year based upon plant, accumulated depreciation, and accumulated deferred income tax balances.

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7.2 CAPEX Adjustment

The resulting CAPEX Adjustment for each Rate Class Grouping shall be reflected in Base Rates pursuant to Section 5.0 above. The Rate Class Grouping CAPEX Adjustment shall be added to the Rate Class Grouping Base Distribution Revenue calculated in Section 6.0 and the Total Rate Class Grouping Base Distribution Revenue shall determine the Benchmark RPC targets in the Company's RDM effective at the start of the second PBR Year.

8.0 Exogenous Events

Exogenous Events are beyond the Company's control and result in the Company incurring costs or cost reductions not reflected in GDPPI, or otherwise in the PBR Adjustment. Costs approved by the Department that result from Exogenous Events are represented by the Z Factor of the PBR%. To qualify for Exogenous Event recovery (whether positive or negative), the following criteria must be met:

(1) the cost must be beyond the Company's control and are not reflected in GDPPI;

(2) the cost arises from a change in accounting requirements or regulatory, judicial, or legislative directives or enactments;

(3) the change is unique to the regional natural gas distribution industry as opposed to the general economy; and

(4) the change exceeds a significance threshold that is noncumulative (i.e., exogenous costs cannot be grouped together into a single total for purposes of determining whether the threshold has been met).

The significance threshold for Exogenous Event cost recovery is $2 million for the annual cost impact of each individual event in the first PBR Year ending September 30, 2022, and thereafter, shall be adjusted annually based on changes in GDPPI.

In addition to the criteria listed above in identifying Exogenous Events and qualifying their costs for recovery (whether positive or negative) through the PBRM, incremental expenses the Company incurs as a result of mandated changes in law, regulations, requirements, standards or practices relating to gas-safety directives arising from the National Transportation Safety Board, the U.S. Department of Pipeline and Hazardous Materials Administration, the Department, or any investigation conducted on behalf of the Department by an outside consultant or expert shall be eligible for Exogenous Event recovery, subject to the significance threshold.

Exogenous Event cost recovery requires that the Company present supporting documentation and rationale to the Department for a determination as to the appropriateness of the proposed recovery or refund. Once allowed by the Department, the amount of the cost change occurring in the Prior Year, or the year prior to the Prior Year and deferred for recovery or refund, shall be recovered from or credited to customers through a separate factor, after review and approval by the Department. The separate factor shall remain in effect until the Exogenous Event cost is fully recovered from or credited to customers, or until such time that the amounts are appropriately reflected in the PBR Adjustment, as applicable.

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9.0 Earnings Sharing Mechanism

In the event that the Company's actual Return on Average Common Equity for any calendar year ending December 31 of the years 2022 through 2026 is within the Earnings Sharing Range shown below, the difference between actual earnings and earnings calculated at the Allowed Return on Equity shall be shared with customers as follows:

Earnings Sharing Range	Share to Customer	Share to Company
9.70% to 11.70%	Deadband, No Sharing of Earnings	
Earnings >11.70%	75%	25%

The Company's Earnings Available for Common Equity used in the calculation shall exclude incentives earned, such as energy efficiency incentives and the Company's share of off system sales; and conversely, would exclude service-quality penalties, as well as any amounts recognized in the current period resulting from regulatory or court settlements or decisions related to prior periods if any.

Earnings Sharing, when applicable, shall result in a per therm credit to customers taking service under retail tariffs. The Company shall submit annual earnings reports with the Department, report on its earnings and whether any earnings fall outside of the Earnings Sharing Range in its annual PBR filings, and any Earnings Sharing shall be recovered from customers through the Company's Local Distribution Adjustment Factor ("LDAF") pursuant to the provisions of its Local Distribution Adjustment Clause ("LDAC") Tariff, M.D.P.U. No. 60, as may be amended from time to time. The amount determined through the Earnings Sharing Mechanism will not be included in the Base Distribution Revenue for purposes of the PBR Adjustment in Section 6.0. Earnings Sharing Factors shall be in effect for a period of one year, subject to full reconciliation and carrying charges and the Bank of America rate, and subject to investigation and approval by the Department.

10.0 Annual PBR Plan Filing

10.1 Filing

The Company shall make a PBR Plan filing by June 15 of each year for proposing new Base Rates and Benchmark RPC targets effective October 1 of the subsequent PBR Year.

10.2 Notice

Each adjustment of the rates under the Company's applicable rate class tariffs shall be in accordance with a notice filed with the Department on or before June 15 setting forth the amount of the (1) PBR Adjustment; (2) the CAPEX Adjustment for the second PBR Year; and (3) the new Rate Components. The notice shall further specify the effective date of such adjustments, which shall be October 1 following the filing of the notice, or such other date as the Department may authorize.

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10.3 Information to be Filed with the Department

As part of its annual filing, the Company shall file information and supporting schedules with the Department necessary for the Department to review and approve the PBR Adjustment for the subsequent PBR Year. Such information shall include the proposed PBR Adjustment calculation, the calculation of the transitional CAPEX Adjustment to be recovered through Base Rates, the descriptions and accounting of any Exogenous Event costs, and the amount of earnings that the Company proposes to be reflected in the LDAF to determine the Earnings Sharing Factors pursuant to Section 9.0. The PBR Plan filings will be made on June 15, 2022 through June 15, 2025 to affect the allowed adjustments of Base Distribution Revenue.

The Company shall also include in its June 15, 2022 PBR Plan Filing all supporting capital documentation for plant investment during the Capital Investment Period, including but not limited to, (1) project descriptions, (2) project sanctioning papers, or project authorization forms, (3) construction work orders, (4) project closure reports, (5) variance analyses explaining the reasons for cost overruns and for demonstrating prudency, and (6) a summary of all proposed projects.

The Company shall also report on its scorecard metrics, as established and directed by the Department in the Company's most recent base distribution rate case, in its June 15 PBR Plan Filings.