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CONFIDENTIAL
MATERIAL
IN COMM FILE

March 23, 2007

RECEIVED
MAR 26 2007
N.H. PUBLIC
UTILITIES
COMMISSION

VIA ELECTRONIC FILING AND OVERNIGHT COURIER

F. Anne Ross, Esq.
New Hampshire Public Utilities Commission
21 S. Fruit St., Suite 10
Concord, New Hampshire 03301

Re: Northern Utilities, Inc., Docket DG 06-098

Dear Ms. Howland:

Enclosed for filing, on behalf of Northern Utilities, Inc. ("Northern"), please find Northern's responses to the following data requests issued in the above-captioned proceeding:

Staff 3-1 Staff 3-2 (Confidential) Staff 3-3 (Confidential)

Staff 3-9 Staff 3-10 Staff 3-11 Staff 3-12 Staff 3-13

Staff 3-14 Staff 3-15 Staff 3-16 (BULK)

Also enclosed are Motions for Protection Orders for CONFIDENTIAL Attachment Staff 3-2 and CONFIDENTIAL Attachment Staff 3-3. Seven copies, stamped CONFIDENTIAL, will be provided to Counsel pursuant to Puc 203.7.

The remaining five (5) responses will be filed as soon as they are available.

Thank you for your attention to this matter

Very truly yours,

Patricia M. French

cc: Ken Traum, OCA
Service List

STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

NORTHERN UTILITIES, INC.	)))	Docket DG 06-098

MOTION FOR PROTECTIVE ORDER

NOW COMES Northern Utilities, Inc. ("Northern") and respectfully requests that the Public Utilities Commission ("Commission") grant it protection for certain confidential information, consistent with R.S.A. 91-A and N.H. Admin. Rules, Puc 204.07. Specifically, Northern requests that the Commission issue its order requiring that customer-specific information provided in connection with Northern's response this date to Staff data request No. Staff 3-2, specifically CONFIDENTIAL Attachment Staff 3-2, be treated as confidential customer information, and not be made part of the public record or available for public disclosure. However, Northern asks to make such information available on a confidential basis to the Commission Staff and the Office of Consumer Advocate.

In support of its Motion, Northern states the following:

1. Northern is filing this date its responses to Staff's third set of data requests in the above referenced proceeding. Part of the filing is detail regarding Northern's largest grandfathered transporting customers which shows customer confidential information, including names, meter readings, peak day mcf, dual fuel capability and monthly usage.

2. Northern seeks to protect this information from public disclosure in order to protect its customers' rights to confidentiality of customer-specific information.

3. R.S.A. 91-A:5(iv) expressly exempts from the public disclosure requirements of Chapter 91-A any records pertaining to "confidential, commercial or financial information." The Commission's rule on public records, Puc 204.07, also allows documents to be protected from public disclosure pursuant to an appropriate order of the Commission.

4. Northern has filed its motion for a protective order to allow it to make available this confidential customer information to Staff and the Consumer Advocate during the Commission's review Northern's Integrated Resource Plan ("IRP"), subject to the requested order from the Commission that such information should be accorded confidential treatment.

5. Northern requests that the Commission issue its order protecting this information from disclosure until such time as a party should appear and request such information, at which time the Commission can weigh the competing interests of Northern's need to continue to protect this information from disclosure against any other party's expressed claim for disclosure.

WHEREFORE, Northern Utilities, Inc. respectfully requests that the Public Utilities Commission issue its Order for Protection as stated herein, and protect from public disclosure CONFIDENTIAL Attachment Staff 3-2.

Respectfully submitted,

NORTHERN UTILITIES, INC.

By its attorney,

Patricia M. French
Lead Counsel
NISOURCE CORPORATE SERVICES
300 Friberg Parkway
Westborough, MA 01581
508.836.7394
508.836.7039 (fax)
pfrench@nisource.com

Dated: March 23, 2007

STATE OF NEW HAMPSHIRE
BEFORE THE
PUBLIC UTILITIES COMMISSION

NORTHERN UTILITIES, INC.	)))	Docket DG 06-098

MOTION FOR PROTECTIVE ORDER

NOW COMES Northern Utilities, Inc. ("Northern") and respectfully requests that the Public Utilities Commission ("Commission") grant it protection from public disclosure over certain confidential, competitively sensitive and proprietary information submitted in this proceeding. In addition, Northern states that this material is not and will not be available in the public domain. However, Northern asks to make such information available on a confidential basis to the Commission Staff and the Office of Consumer Advocate.

1. Northern seeks protection over its response to Staff 3-3 in the above proceeding, in particular, CONFIDENTIAL Attachment Staff 3-03 (BULK).

2. In summary, Northern seeks protection over supplier overtakes on Non-Daily Metered Pools of the competitive suppliers and marketers in its service territory.

1. R.S.A. 91-A:5(iv) expressly exempts from the public disclosure requirements of Chapter 91-A any records pertaining to "confidential, commercial or financial information." The Commission's rule on public records, Puc 204.07, also allows documents to be protected from public disclosure pursuant to an appropriate order of the Commission.

2. Northern has filed its motion for a protective order to allow it to make available this confidential customer information to Staff and the Consumer Advocate, subject to the requested order from the Commission that such information should be accorded confidential treatment.

3. Northern requests that the Commission issue its order protecting this information from disclosure until such time as a party should appear and request such information, at which time the Commission can weigh the competing interests of Northern's need to continue to protect this information from disclosure against any other party's expressed claim for disclosure.

4. The marketers and suppliers operate in a competitive environment. The Staff requested specific information regarding the operations of non-daily metered pool of the suppliers and marketers in Northern's service territory. In order to provide the requested information, Northern must disclose Northern's confidential information relative to the loads of the competitive entities serving Northern's large transportation customers.

5. The loads and pool characteristics of any particular competitive supplier are not available at any time in the public domain.

6. Protection over this information is appropriate.

WHEREFORE, Northern Utilities, Inc. respectfully requests that the Public Utilities Commission issue its Order for Protection as stated herein, and protect from public disclosure CONFIDENTIAL Attachment Staff 3-3 (BULK).

Respectfully submitted,

BAY STATE GAS COMPANY

By its attorney,

Patricia M. French
Lead Counsel
NISOURCE CORPORATE SERVICES
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fax (508) 836-7039

DATED: March 23, 2007

Northern Utilities, Inc.
New Hampshire Division
DG 06-098
Staff Request Set No. 3
Response: 1
Responsible: Joseph A. Ferro
Manager, Regulatory Policy

Request: Are suppliers, on behalf of New Hampshire non-grandfathered transportation customers, assigned and billed for capacity during the twelve-month period of November through October? If not, how are those suppliers assigned and billed capacity? Please explain in detail.

Response: Yes. Suppliers of non-grandfathered transportation customers are billed for capacity monthly at the pipeline's and storage provider's monthly maximum rates, as well as for the cost of Northern's company-managed resources established each November 1. Annual costs of assigned capacity are charged to suppliers over the period in which the costs are incurred or charged to Northern. For instance, most pipeline capacity is released by Northern and therefore charged to suppliers by the pipelines each month for the twelve-month period, while Northern typically bills for peaking (company-managed) resources over the six-month period, November through April. Please also note that the percentages of capacity resources (Capacity Allocators) of a supplier pool's Total Capacity Quantity ("TCQ") that determine the assignment of resources are established each November 1 and are in effect through October 31.

I attest this response was prepared by me or under my direct supervision and control and is true and accurate as to the best of my information and belief at the date of filing.

Northern Utilities, Inc.
New Hampshire Division
DG 06-098
Staff Request Set No. 3
Response: 2
Responsible: Joseph A. Ferro
Manager, Regulatory Policy

Request: Please provide a list of grandfathered customers and the actual monthly, annual and peak day usage for each of those customers over the most recent twelve month period available. Please indicate if a customer has backup fuel capability on site, the type of backup fuel and the ability to utilize that capability if natural gas service is interrupted. Describe energy alternatives available for each customer and the estimated cost of conversion.

Response: CONFIDENTIAL Attachment Staff 3-2 provides the information requested for the New Hampshire Division's grandfathered transportation customers, with the exception that Northern has no basis for estimating a specific customer's conversion cost to have alternate fuel capability.

CONFIDENTIAL Attachment Staff 3-2 is being filed pursuant to Northern's Motion for Protective Order

I attest this response was prepared by me or under my direct supervision and control and is true and accurate as to the best of my information and belief at the date of filing.

Northern Utilities, Inc.
New Hampshire Division
DG 06-098
Staff Request Set No. 3
Response: 3
Responsible: Joseph A. Ferro
Manager, Regulatory Policy

Request: For each existing grandfathered customer, please provide a history of supplier failure to deliver. Please describe the specifics of each failure (i.e., customer specific or supplier pool shortfall to multiple customers, under-nominated for daily requirements (other than for normal over/under daily imbalances), supply curtailment, pipeline constraint, etc.). Include the dates, volumes, percentage of supply not delivered and whether or not the failure to deliver occurred during a pipeline OFO or on a peak day.

Response: Suppliers to Northern's New Hampshire Division transportation customers are allowed to aggregate their customers into Daily-Metered and Non-Daily-Metered pools, in accordance with Northern's Delivery Service Terms and Conditions ("T&Cs"). Thus, these suppliers submit daily nominations as one volume for the entire pool. Hence, Northern does not have nominations by customer to compare to that customer's daily usage. Accordingly, daily imbalances by customer are not captured also, nor can they be historically calculated.

CONFIDENTIAL Attachment Staff 3-3 (BULK) provides the information requested at the most detailed level possible, by daily-metered pool. This bulk attachment is sorted for the period November 2001 through February 2007 by day, in order of largest under-delivery (negative percentage daily imbalance) to largest over-delivery (positive percentage daily imbalance).

Please note that certain grandfathered customers were their own aggregation pool in earlier times, but virtually all are now part of a larger aggregation pool. Net Nominations ("Net Nom") are presented prior to any imbalance trading between suppliers, as allowed and described in Section 9.6.6 of Northern's T&Cs. Supplier Imbalance trading typically happens at the end of each calendar month. All but two of the New Hampshire Division's grandfathered accounts are daily metered. Thus, the daily imbalance analysis of the daily-metered pools essentially represents the daily usage and associated imbalances of the grandfathered customer group.

CONFIDENTIAL Attachment Staff 3-3 (BULK) is being filed pursuant to Northern's Motion for Protective Order

I attest this response was prepared by me or under my direct supervision and control and is true and accurate as to the best of my information and belief at the date of filing.

Northern Utilities, Inc.
New Hampshire Division
DG 06-098
Staff Request Set No. 3
Response: 9
Responsible: Joseph A. Ferro
Manager, Regulatory Policy
Francisco C. DaFonte
Director, Energy Supply Services

Request: What is the incremental benefit (relative to the current design-day standard) associated with Northern creating the agreed capacity reserve? In responding to the question, please specify: (i) the assumed outage cost avoided; and (ii) the likelihood of the outage's occurrence. Please also explain how the incremental benefit is allocated between, on the one hand, firm sales and firm transportation customers and, on the other, grandfathered customers.

Response: Please see Northern's response to Staff 1-24.

We attest this response was prepared by us or under our direct supervision and control and is true and accurate as to the best of our information and belief at the date of filing.

Northern Utilities, Inc.
New Hampshire Division
DG 06-098
Staff Request Set No. 3
Response: 10
Responsible: Joseph A. Ferro
Manager, Regulatory Policy
Francisco C. DaFonte
Director, Energy Supply Services

Request: Please explain the basis of the avoided outage cost estimate and provide all supporting analyses.

Response: Please see Northern's response to Staff 1-25.

We attest this response was prepared by us or under our direct supervision and control and is true and accurate as to the best of our information and belief at the date of filing.

Northern Utilities, Inc.
New Hampshire Division
DG 06-098
Staff Request Set No. 3
Response: 11
Responsible: Joseph A. Ferro
Manager, Regulatory Policy
Francisco C. DaFonte
Director, Energy Supply Services

Request: Please explain how the probability of occurrence was determined and provide all supporting analyses.

Response: Please see Northern's response to Staff 1-25.

We attest this response was prepared by us or under our direct supervision and control and is true and accurate as to the best of our information and belief at the date of filing.

Northern Utilities, Inc.
New Hampshire Division
DG 06-098
Staff Request Set No. 3
Response: 12
Responsible: Francisco C. DaFonte
Director, Energy Supply Services

Request: Please express the incremental reliability benefit associated with the capacity reserve in terms of a reduction in EDD.

Response: Please see Northern's response to Staff 1-26.

I attest this response was prepared by me or under my direct supervision and control and is true and accurate as to the best of my information and belief at the date of filing.

Northern Utilities, Inc.
New Hampshire Division
DG 06-098
Staff Request Set No. 3
Response: 13
Responsible: Joseph A. Ferro
Manager, Regulatory Policy
Francisco C. DaFonte
Director, Energy Supply Services

Request: What is the incremental cost of the resources necessary to support the proposed capacity reserve? Please provide the analysis underlying this cost estimate. Please also explain: (i) how this incremental cost is allocated between, on the one hand, firm sales and firm transportation customers and, on the other, grandfathered customers; and (ii) the basis of this allocation.

Response: Please see Northern's response to Staff 1-27.

We attest this response was prepared by us or under our direct supervision and control and is true and accurate as to the best of our information and belief at the date of filing.

Northern Utilities, Inc.
New Hampshire Division
DG 06-098
Staff Request Set No. 3
Response: 14
Responsible: Joseph A. Ferro
Manager, Regulatory Policy
Francisco C. DaFonte
Director, Energy Supply Services

Request: What is the estimated net benefit associated with the creation of the agreed capacity reserve expressed in: (i) total dollars; and (ii) in terms of a benefit/cost ratio?

Response: Please see Northern's response to Staff 1-28.

We attest this response was prepared by us or under our direct supervision and control and is true and accurate as to the best of our information and belief at the date of filing.

Northern Utilities, Inc.
New Hampshire Division
DG 06-098
Staff Request Set No. 3
Response: 15
Responsible: Francisco C. DaFonte
Director, Energy Supply Services

Request: Does the Company's capacity release policy require that all capacity be subject to recall? If not, please explain. If yes, please provide a copy of the relevant terms and conditions.

Response: Please see Northern's response to Staff 1-29.

I attest this response was prepared by me or under my direct supervision and control and is true and accurate as to the best of my information and belief at the date of filing.

Request: Please provide all testimony and orders related to the Bay State Gas Co. Jan. 24 filing with the DTE requesting a 13% capacity reserve.

Response: Attached are the filings made by Bay State Gas in Docket DTE 06-36, before the Department of Telecommunications and Energy.

Attachment Staff 3-16 (a) is Bay State's Initial Filing made on March 31, 2006, pursuant to the Order issued in Bay State's Rate Case (DTE 05-27).

Attachment Staff 3-16 (b) is Bay State's Notice of Amendment, dated October 5, 2006.

Attachment Staff 3-16 (c) is Bay State's Amended Filing dated October 6, 2006, which was required due to the data clarification and revised incremental planning standard, equal to 13% of capacity exempt design day load, as identified by Bay State.

Attachment Staff 3-16 (d) is Bay State's Tariff re-filing, dated January 23, 2007, to revise the effective date of the tariff pages in order to accommodate the procedural schedule of the case.

No order has been issued at this time in Docket DTE 06-36..

I attest this response was prepared by me or under my direct supervision and control and is true and accurate as to the best of my information and belief at the date of filing.

NiSource
Corporate Services

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March 31, 2006

VIA COURIER

Mary L. Cottrell, Secretary
Department of Telecommunications and Energy
One South Station
Boston, MA 02110

Re: **Bay State Gas Company, D.T.E. 05-27**
Compliance Tariff for Proposal for Grandfathered Overtakes

Dear Ms. Cottrell:

Enclosed on behalf of Bay State Gas Company ("Bay State"), pursuant to the order of the Department of Telecommunications and Energy in D.T.E. 05-27, please find an original and 14 copies of the following:

1. Bay State's Petition for Approval of System Protection Plan for Grandfather Overtakes;

2. Proposed M.D.T.E. No. 35 (Index Page, Section 2, Section 13 and Appendix C) and M.D.T.E. No. 36; and,

3. The Testimony and Exhibits of Joseph A. Ferro, Bay State's Manager, Regulatory Policy, in support thereof.

In D.T.E. 05-27, the Department directed Bay State to submit for Department review a complete proposal for monitoring overtakes by grandfathered transportation customers that addresses the directives in D.T.E. 02-75-A. Bay State Gas Company, D.T.E. 05-27, p. 356 (2005). The directives in D.T.E. 02-75 require Bay State to, inter alia, implement a system under which Bay State would have the ability to "monitor usage" by its grandfathered customers and then submit a report to the Department to explain how such a system would work. Today's filing describes Bay State's excessive difficulty in devising such a plan that would be effective for system protection and would be cost-efficient to deploy. Bay State proposes an alternative for the Department's consideration, that is, implementation of an incremental capacity planning standard, that it believes will address the core issue of system protection.

Please do not hesitate to contact me at (508) 836-7394 or Robert L. Dewees, Jr., of Nixon Peabody LLP, at (617) 345-1316 with any questions concerning this filing.

Very truly yours,

Patricia M. French

cc: Andrew O. Kaplan, Esq., General Counsel, DTE
Kevin Brannelly, Director, Rates and Revenue Requirements, DTE
George Yiankos, Director, Gas Division, DTE
Joseph W. Rogers, Office of the Attorney General

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March 31, 2006

VIA COURIER

Kevin Brannelly, Director
Rates and Revenue Division
Department of Telecommunications and Energy
One South Station
Boston, MA 02110

Re: Bay State Gas Company, D.T.E. 05-27
Compliance Tariff for Proposal for Grandfathered Overtakes

Dear Mr. Brannelly:

Enclosed on behalf of Bay State Gas Company ("Bay State"), pursuant to the order of the Department of Telecommunications and Energy in D.T.E. 05-27, please find the following:

1. Bay State's Petition for Approval of System Protection Planning Standard for Grandfather Overtakes;

2. Proposed M.D.T.E. No. 35 (Index Page, Section 2, Section 13 and Appendix C) and M.D.T.E. No. 36; and,

3. The Testimony and Exhibits of Joseph A. Ferro, Bay State's Manager, Regulatory Policy, in support thereof.

In D.T.E. 05-27, the Department directed Bay State to submit for Department review a complete proposal for monitoring overtakes by grandfathered transportation customers that addresses the directives in D.T.E. 02-75-A. Bay State Gas Company, D.T.E. 05-27, p. 356 (2005). The directives in D.T.E. 02-75 require Bay State to, inter alia, implement a system under which Bay State would have the ability to "monitor usage" by its grandfathered customers and shut off customers that overtake on a Critical Day. Bay State was further directed to submit a report to the Department to explain how such a system would work. Today's filing describes Bay State's investigation of the implementation considerations associated with the monitoring and shutoff plan that would be effective on a Critical Day. For the reasons explained in the accompanying filing, Bay State's investigation determined that the Department's proposal is not effective from either an operational or system reliability perspective, or from a cost perspective. Accordingly, Bay State is presenting an alternative for the Department's consideration that is consistent with the directives of the Department on this matter in previous dockets. Bay State's alternative includes implementation of an incremental capacity planning standard that it believes will address the core issue of system protection and tariff changes that provide for the recovery of costs associated with the capacity planning standard from grandfathered customers as well as the monitoring of overtakes by grandfathered customers.

Please do not hesitate to contact me at (508) 836-7394 or Robert L. Dewees, Jr., of Nixon Peabody LLP, at (617) 345-1316 with any questions concerning this filing.

Very truly yours,

Patricia M. French

cc: Mary L. Cottrell, Secretary, DTE
Andrew O. Kaplan, Esq., General Counsel, DTE
George Yiankos, Director, Gas Division, DTE
Joseph W. Rogers, Office of the Attorney General

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

BAY STATE GAS COMPANY **Grandfathered Overtakes**	)	**D.T.E. 05-27**

MOTION OF BAY STATE GAS COMPANY
FOR APPROVAL OF
SYSTEM PROTECTION PLANNING STANDARD
FOR GRANDFATHERED OVERTAKES

Pursuant to 220 C.M.R. § 1.04(5), Bay State Gas Company ("Bay State" or the "Company") requests that the Department of Telecommunications and Energy ("the Department") approve its proposal to implement changes to its resource planning process that provide for an incremental capacity planning standard to protect the system against the reliability risks posed by grandfathered customers, and to approve tariff modifications that would allow Bay State to recover the associated costs from grandfathered transportation customers. Bay State is required to file this proposal pursuant to the Department's order in D.T.E. 05-27.

I. INTRODUCTION

In D.T.E. 05-27, the Department directed Bay State to submit for Department review a complete proposal for monitoring overtakes by grandfathered transportation customers that addresses the directives in D.T.E. 02-75-A. Bay State Gas Company, D.T.E. 05-27, p. 356 (2005). The directives in D.T.E. 02-75 require Bay State to, inter alia, implement a system under which Bay State would have the ability to "monitor usage" by its grandfathered customers and then submit a report to the Department to explain how such a system would work. Today's filing describes Bay State's excessive difficulty in devising such a plan that would be operationally effective on a Critical Day and would be cost-efficient to deploy. Bay State proposes an alternative for the Department's consideration that it believes will address the core issue of system protection.

II. SUMMARY OF PROPOSAL

Bay State's proposal is to introduce an incremental planning standard into the Company's resource planning process. The planning standard would provide for the inclusion of thirty percent (30%) of grandfathered customer loads (design day requirements) in Bay State's requirements forecasted for planning purposes. Consistent with this proposal, Bay State today files modifications to its Distribution and Default Terms and Conditions in M.D.T.E. No. 35 that provide for the recovery of the costs attributable to the required resources. In the tariff, M.D.T.E. Nos. 35 and 36, Bay State proposes to recover these costs consistent with cost-causation principles: from grandfathered, capacity-exempt customers. Finally, Bay State presents changes to its nomination and balancing protocols also reflected in M.D.T.E. No. 35 that would allow the Company to monitor more closely the potential for unauthorized overtakes by grandfathered customers.

III. BACKGROUND

A. Bay State Plans its System to Serve Reliably its Firm Customers

Bay State acquires and manages upstream capacity resources needed to ensure reliable service for its customers. Upstream capacity resources include long-haul transportation from natural gas producing areas, such as the Gulf of Mexico, as well as short-haul transportation from storage areas in Pennsylvania, Ohio and New York, to Bay State's city gates, along with associated storage capacity. Bay State supplements these resources with third-party peaking resources, such as those obtained from Distrigas, and its own on-system liquefied natural gas ("LNG") and liquefied petroleum gas ("LPG") resources.

Capacity resources are acquired by Bay State on a long-term basis and require substantial fixed-cost commitments. Bay State's capacity planning and acquisition process is deliberative and seeks to obtain a best-cost portfolio of resources that balances portfolio cost with the vital attributes of reliability, flexibility and diversity. Bay State accomplishes this by examining its demand forecast and knowledge of impending changes to existing resources, by systematically investigating all resource alternatives, and by developing an action plan. The Resource Action Plan identifies each of the specific steps that should be taken to address the acquisition of incremental resources or implement changes to existing resources. Bay State's resource planning processes have been reviewed and approved by the Department. See e.g., Bay State Gas Company, D.T.E. 02-75 (2004).

Once resources are acquired, Bay State continually balances the portfolio to reflect changes in firm demand on the system every day. When demand for its system resources by firm customers weakens temporarily, Bay State actively participates in secondary capacity markets in order to mitigate the fixed costs of the necessary system resources that are maintained in its portfolio. The mitigation revenues provided by the secondary market are opportunistic in character and are achieved through capacity release and off-system sales transactions.

B. The Department's Capacity Assignment Policy Protects Firm Customers

Wholesale capacity markets are insufficiently competitive to support retail competition at the current time and as a result, mandatory capacity assignment protects firm retail customers from system reliability issues and service disruptions. D.T.E. 04-01. The Department's capacity assignment policy requires all firm transportation customers to accept a pro rata share of capacity from the incumbent gas utility at the time the customer selects transportation service. Natural Gas Unbundling, D.T.E. 98-32-B (1999). The capacity is managed by the supplier portfolio of resources, but is recallable if the customer returns to sales service or the supplier defaults on its obligations.

Mandatory capacity assignment is the critical tool enabling Bay State to plan for the requirements of its firm customers and to maintain system reliability in an unbundled operating environment. Unbundled markets encourage natural gas marketers to enter and exit markets based on their competitive opportunities, both within and without of the Commonwealth; the result is that Bay State is exposed to substantial variation in load for firm sales service as customers come and go from the system. Bay State is similarly exposed to the market risk that suppliers will under-deliver the requirements of their customers, jeopardizing Bay State's ability to ensure the operational integrity of the service to its firm customers. The ability to recall capacity assigned on a mandatory basis is necessary for Bay State to ensure that such situations do not result in harm to firm service to other customers.

C. Bay State Seeks to Address the Operational Risk Posed by Grandfathered Customers

Particular to Bay State's instant proposal, historical policy considerations have permitted certain customers to be exempt (or "grandfathered") from the rules requiring mandatory capacity assignment: (1) any customer on firm transportation service as of February 1, 1999; and (2) any customer that commences service initially on a firm transportation rate.[1] Under-delivery by a supplier serving grandfathered customers is equally as serious as the system reliability concerns that led to the establishment and reaffirmation of mandatory capacity assignment. However, unlike with respect to non-grandfathered customers, Bay State has no way of recalling assigned capacity to address supplier under-deliveries to grandfathered customers. Bay State has historically had larger numbers of grandfathered, capacity exempt customers than other gas companies in the Commonwealth. Bay State believes it is distinctly situated.

1. Reverse Migration of Grandfathered Customers

In recent years, Bay State has endured reverse migration that included millions of mcf of demand attributable to grandfathered customers that were returned to Bay State without any of the associated capacity necessary to plan for or to serve them without impinging on the reliability insured for other firm sales customers. Although the Department has decided that gas companies are not obligated to accept the reverse migration of grandfathered customers, service continuity and access to reliable fuel sources is necessary for large industrial customers and it truly benefits other customers, the local economy and the broader economic well-being of the State. See, e.g., Bay State Gas Company, D.T.E. 02-75 (2004). Unlike the marketers, Bay State is embedded in the communities it serves. As a public service company, it is inappropriate for it to be put in the position where it must ignore the needs of a corporate citizen employing a workforce in a community it serves, especially if the cause of the reverse migration is the demise of the marketer or the volatility of gas supply pricing, over which neither Bay State nor the customer

1 Grandfathered status is in the nature of a privilege, not a right. Customers may lose their grandfathered status if they elect to be served under a firm sales service rate schedule, even if they later move back to transportation service.

have any control. But reverse migration is not Bay State's only concern. The potential under-delivery by suppliers serving grandfathered customers presents an even greater operational risk for Bay State.

2. Supplier Under-Deliveries for Grandfathered Customers

Because of the number of customers transporting on Bay State's system, Bay State relies upon supplier deliveries of natural gas to Bay State's city gate to maintain operational reliability of service to all customers. To the extent that a supplier fails to deliver required volumes to Bay State's city gate, the integrity of Bay State's system is jeopardized, especially were the failure to occur during a period of overall high demand or physical disruption in wholesale markets. The additional supplier volumes combine with Bay State's resources and together are required to maintain system pressure. Bay State delivers natural gas to customers through miles of piping that physically integrates neighborhoods, towns, cities and regions. The impact of supplier under-deliveries or failure to deliver could not be limited in such a way that will permit Bay State to protect its customers.

For years, in each of the many instances where suppliers have under-delivered their customers' requirements, circumstances have permitted Bay State to make up the difference through the resources it maintains to provide sales service. Reliability of service comes first; the financial resolution follows later. However, it is simply fortuitous that in those circumstances, Bay State has had that ability to meet the requirements of such under-deliveries, as the potential occurrences were not integrated in its resource planning standards. Bay State sees it as a "not if, but when" will suppliers under-deliver on a Critical Day when Bay State's own supply is so constrained that it is unable to make up the short-fall to serve grandfathered customers from its own portfolio. For this reason, the operational risks associated with grandfathered customers are far greater than for traditional firm transportation customers.

3. Market Fundamentals Affect Bay State's Ability to Reach Short-Term Capacity and Supply

Much of the incremental capacity being developed to serve Northeast markets is dedicated to gas-fired electric generation markets and to meeting the growing needs of traditional residential and commercial customers. Analysts indicate that a tightening demand-supply balance has contributed to substantial price volatility and a substantial reduction in market liquidity. Upstream, consolidations have reduced the number of producers. Tightening creditworthiness standards toughen the economic benchmark for wholesale marketers to compete. The operational risks associated with capacity exempt, grandfathered loads have increased over time.

Market forces alone are insufficient to protect customers. The supply response is much slower than the demand response in gas markets creating localized and regional constraints from time-to-time. This is primarily due to the need to construct infrastructure to deliver commodity supplies to markets, and also delays in bringing on incremental production capability. The lead time for incremental pipeline capacity is typically three years, as a result of environmental issues and regulatory lags.

D. Previous Bay State Proposals to Deal with System Imbalance

In its most recent integrated resource plan filing, D.T.E. 02-75, Bay State presented a proposal to address the operational risks associated with grandfathered loads as well as the potential for wholesale market disruptions that occur from time-to-time: a ten-percent "contingency" reserve. The Department ultimately rejected this proposal on the basis that it would be inconsistent with the Department's cost-causation principles and would result in cost shifting.

IV. BAY STATE'S PROPOSAL FOR AN INCREMENTAL PLANNING STANDARD SHOULD BE APPROVED

As described in detail in Exhibit BSG-1, the testimony of Joseph A. Ferro, it is economically and operationally infeasible to implement a monitoring process that will effectively provide the capability of Bay State to shut off customers in order to avert a crisis or other system emergency on a Critical Day. Therefore, as Mr. Ferro describes in detail, Bay State proposes an incremental planning standard addressed towards the specific customers that are responsible for the system reliability concerns. Bay State proposes to maintain access to capacity sufficient to meet thirty percent of the design day requirements of grandfathered loads on its system at any given point in time.

When approved, the proposed planning criteria translates into a capacity planning standard that would substantially limit the increased operational risks of grandfathered loads compared to Bay State's own system supply service. The costs of the capacity relied upon to meet this planning standard would be recovered solely from grandfathered customers through a charge whose revenues are credited to Bay State's cost of gas adjustment ("CGA"). The capacity utilized by Bay State to meet this planning criteria would be sold in secondary markets when it is not utilized by Bay State, mitigating the overall cost of maintaining the standard. The details and justifications are provided in Exh. BSG-1. The incremental planning standard is in the public interest.

V. CONCLUSION

WHEREFORE, based on the foregoing, Bay State requests that the Department approve its proposal for an incremental capacity planning standard to provide system protection against overtakes by grandfathered customers.

Respectfully submitted,

BAY STATE GAS COMPANY

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Dated: March 31, 2006

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2.0 DEFINITIONS

Adjusted Target Volume ATV	The volume of Gas determined pursuant to Section 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.
Authorization 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.

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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.
Capacity Exempt Customer	Any Customer receiving Distribution Service whose TCQ is equal to zero as provided for in either Section 13.3.3 or Section 13.3.5 of these Terms and Conditions.
City Gate	The interconnection between a Delivering Pipeline and the Company's distribution facilities.
Company	Bay State Gas Company
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 19.0 of these Terms and Conditions, a Day declared at any time by the Company in its reasonable discretion when unusual operating

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	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 MDTE approves a suitable replacement.
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.
Default Service	Gas commodity service provided to a Customer who is not receiving Supplier Service, in accordance with Section 15.0 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.
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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.
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 25.0 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.
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.

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Gas Service Area	An area within the Company's distribution system as defined in Section 4.0 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.
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 17.0 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 Suppliers' Peaking Service Account pursuant to Section 16.0 of these Terms and Conditions shall be equal to the sum of the Customers' MDPQs in a Supplier's Aggregation Pool.
MDTE	The Massachusetts Department of Telecommunications and Energy.
Month	A calendar month of Gas Days.
Monthly Index	The average of the Daily Indices for the relevant Month.

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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, and other such non-confidential information as may be reasonably required by the Company.
Off-Peak Season	The consecutive months May to October, inclusive.
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 19.0 of these Terms and Conditions.
Peak Day	The forecasted Gas Day during which the Company's system experiences the highest aggregate Gas Usage as approved by the MDTE.
Peaking Capacity	Capacity normally used by the Company to provide Peaking Service.
Peak Season	The consecutive months November to April, inclusive.
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 maximum balance in the account shall equal the Peaking Supply assigned to the Supplier pursuant to these Terms and Conditions.

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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 post the Peaking Service Rule Curve on its Website as identified in Section 23.0 of these Terms and Conditions
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.
Pre-Determined Allocation	Instructions from the Supplier to the Company for the allocation of discrepancies in confirmed nominations among the Supplier's Aggregation Pools and/or Customers as set forth in the Supplier's Service Agreement.
Reference Period	A period of at least twelve (12) months for which a Customer's Gas Usage information is typically available to the Company.

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Supplier	Any entity licensed by the MDTE 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	Contracts for capacity in off-system storage Capacity facilities used to accumulate and maintain gas inventories for redelivery to the Company's city gates.
Underground Storage Withdrawal Capacity	Capacity for the withdrawal of gas inventories 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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13.0 CAPACITY ASSIGNMENT

13.1 Applicability

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

13.2 Identification of Capacity for Assignment

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

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

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

13.3 <u>Determination of Pro-Rata Shares of Capacity</u>

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

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

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

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

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

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

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

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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 16.0 of these Terms and Conditions.

13.4 <u>Capacity Assignments</u>

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

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

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

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

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

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

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

13.5 Release of Contracts

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

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

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

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

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

13.6 Annual Reassignment of Capacity

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

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

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

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13.7 Recall of Capacity

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

13.8 <u>Underground Storage Capacity</u>

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

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

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

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

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

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13. 9 Company-Managed Supplies

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

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

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

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

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

13.10 Open-Season Capacity Assignments

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

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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 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.

13.12 Capacity Exempt Customer Reliability Charge

13.12.1 The Company requires access to firm upstream pipeline, storage and peaking capacity as well as on-system peak-shaving resources to maintain the reliability of its distribution system operations. The Capacity Exempt Customer Reliability Charge (CECRC) allows the Company to recover the costs of such resources required in proportion to the level of Capacity Exempt Customer loads on its system.

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13.12.2 Each year, the Company shall calculate a CECRC rate per therm applicable to all Capacity Exempt Customer throughput for the annual period beginning November 1. The CECRC rate per therm and the associated derivation shall be set forth in Appendix C to these Terms and Conditions.

13.12.3 The CECRC rate per therm shall be calculated as follows:

(1) Allowable CECRC costs shall equal the sum of the following;

(a) The product of the total Capacity Exempt Customer peak day requirements, determined prior to November 1, the system average annual unit capacity cost, and a factor of 30% (thirty percent).

(b) A capacity release and off-system sales revenue credit equal to the total projected annual capacity release and off-system sales margin revenues for the annual period beginning November 1 multiplied by the ratio of the total Capacity Exempt Customer peak day requirements to the total system peak day requirements.

(c) Any difference, positive or negative, between the costs of the CECRC as established for the previous annual period November 1 through October 31 and the actual collections from the application of the CECRC rate to Capacity Exempt Customer throughput for the corresponding period.

13.12.4 The total revenues recovered pursuant to the CECRC shall be credited to the Company's CGA costs in accordance with M.D.T.E. No. 36.

13.13 <u>Monitoring Capacity Exempt Customer Overtakes</u>

13.13.1 Overtakes associated with Capacity Exempt Customer loads threaten the reliability of Bay State's distribution system. Therefore, the Company shall monitor Supplier overtakes associated with Capacity Exempt Customer loads on Critical Days.

13.13.2 All Capacity Exempt Customers served by a Supplier that experiences an overtake on a Critical Day that exceeds thirty percent (30%) of the aggregate Gas Usage of Capacity Exempt Customers within its Aggregation Pool shall lose their status as exempt from the mandatory capacity assignment provisions of these Terms and Conditions. In order to determine whether a Supplier has exceeded the allowed 30% overtake for Capacity Exempt Customer loads, the Company shall perform the following calculations

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applicable to Daily-Metered and Non-Daily Metered Aggregation Pools for each day that the Company declares a Critical Day and provides notice thereof to Suppliers pursuant to Section 19.0 of these Terms and Conditions.

(1) For Daily Metered Pools, the Company shall determine the receipts applicable to Capacity Exempt Customer loads by subtracting the total metered Gas Usage for all non-Capacity Exempt Customers in the Aggregation Pool divided by a factor of one hundred and two percent (102%) from the total deliveries for the Aggregation Pool. The total Gas Usage for all Capacity Exempt Customers in the Aggregation Pool shall be subtracted from the receipts for Capacity Exempt Customers calculated pursuant to this provision to determine the overtake applicable to Capacity Exempt Customers, if any. The percentage overtake shall be determined by dividing the Capacity Exempt Customer overtake into the total Gas Usage for all Capacity Exempt Customers in the Aggregation Pool.

(2) For Non-Daily Metered Pools, the Company shall calculate the percentage overtake for the Aggregation Pool by subtracting the ATV from the actual receipts from the Supplier. The percentage overtake for the Aggregation Pool shall be determined by dividing the overtake for the Aggregation Pool by the ATV. The percentage overtake for Capacity Exempt Customers in the Non-Daily Metered Aggregation Pool shall equal the percentage overtake for the total Aggregation Pool.

(3) The calculation of Capacity Exempt Customer overtakes shall not take into consideration trading of daily imbalances by Suppliers as permitted under Section 24.7.

13.13.3 All Capacity Exempt Customers of a Supplier whose overtake on a Critical Day exceeds thirty percent as calculated pursuant to Section 13.13.2 shall forego their capacity assignment exemption. Further, each Supplier serving said Capacity Exempt Customers shall be assigned capacity pursuant to these Terms and Conditions on the next allowable assignment date.

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APPENDIX C

Capacity Exempt Customer Reliability Charge

Row	Description	Amount	Calculation
(1)	Capacity Exempt Customer Peak Day	XX Dth	
(2)	Average Annual Unit Capacity Cost	$__ per Dth	
(3)	Factor	30%	
(4)	Reliability Costs		(1) x (2) x (3)
(5)	Capacity Release / OSS Margin Revenues	$___	
(6)	Total System Design Day	XX Dth	
(7)	Capacity Release / OSS Credit		(5) x ((1)/(6)
(8)	Prior Period Under / (Over) Recovery	$___	
(9)	Total CECRC Allowable Costs for Period	$____	(4) + (7) + (8)
(10)	Capacity Exempt Customer Throughput	Dth	
(11)	CECRC Charge per therm	$____	(9) / (10)

COST OF GAS ADJUSTMENT CLAUSE

Section

1.0 Purpose

The purpose of this clause is to establish procedures that allow Bay State Gas Company ("Bay State" or the "Company"), subject to the jurisdiction of the Department of Telecommunications and Energy ("Department") to adjust, on a semiannual basis, its rates for firm gas sales service in order to recover the costs of gas supplies, along with any taxes applicable to those supplies, pipeline and storage capacity, production capacity and storage, bad debt expense associated with purchase gas costs, and the costs of purchased gas working capital, to reflect the seasonal variation in the cost of gas, and to credit all supplier refunds and the margins above the Annual Threshold associated with capacity credits from non-core sales and transportation, interruptible sales and transportation and capacity release sales, as well as revenues from the billing of the Capacity Exempt Customer Reliability Charge, to firm ratepayers.

2.0 Applicability

This Cost of Gas Adjustment Clause ("CGAC") shall be applicable to Bay State and all firm gas sales made by Bay State, unless otherwise designated. The application to the clause may, for good cause shown, be modified by the Department. See Section 13.0, "Other Rules."

COST OF GAS ADJUSTMENT CLAUSE

3.0 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, other gas supply expense incurred to procure and transport supplies and bad debt percent (from the last general rate case) applied to allowable CGAC costs for the forecast period, 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 filings outlined in Section 12.0.

4.0 Effective Date of Gas Adjustment Factor

The date on which the seasonal Gas Adjustment Factors ("GAF") become effective shall be the first day of the first month of each season as designated by the Company. Unless otherwise notified by the Department, the Company shall submit GAF filings as outlined in Section 12.0 of this clause at least 45 days before they are to take effect.

5.0 Definitions

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

(1) **Annual Threshhold** - A threshold level of margins, established annually and separately for Capacity Release, Interruptible Sales and Off-System Sales, based on the twelve months ended April 30 each year, the level above which the Company retains 25% of such margins.

(2) **Bad Debt Expense** - is the uncollectable expense attributed to the Company's gas costs plus allowable working capital derived from the gas cost portion of bad debt.

(3) **Base Load Requirements** - The annual quantity of gas supply needed to satisfy the lowest level of firm demand based on the average July and August loads.

(4) **Capacity Exempt Customer Reliability Charge ("CECRC") Revenues** - The revenues from billing the CECRC to capacity exempt firm transportation customers for the cost of capacity resources needed for system reliability and based on 30% of the capacity exempt design day requirements.

(5) **Capacity Release Revenues** - The economic benefit derived from the sale of upstream capacity.

(6) **Carrying Charges** - Interest expense calculated on the average monthly balance using the consensus prime rate as reported in the *Wall Street Journal.*

(7) **Economic Benefit** - The difference between the revenues received and the marginal cost determined to serve non-core customers.

COST OF GAS ADJUSTMENT CLAUSE

(8) **Interruptible Sales Margins** - The economic benefit derived from the interruptible sale of gas downstream of the Company's distribution system.

(9) **Inventory Finance Charges** - As incurred or billed each month for the carrying costs on the value of the balance of inventory gas for the respective month. The total charges shall represent an accumulation of the projected monthly charges as calculated using the monthly average of financed inventory at the existing (or anticipated) financing rate of the Company or through a trust or other financing vehicle.

(10) **Local Production Capacity and Storage Costs** - Include the ancillary supply costs of providing local manufactured gas, gas dispatching, gas acquisition, and miscellaneous A&G costs as determined in the Company's most recent rate proceeding.

(11) **SMBA** – Simplified Market Based Allocation Method - Used in determining the allocation of gas costs among High and Low Load Factor classes.

(12) **Non-Core Commodity Costs** - The commodity cost of gas assigned to non-core sales to which the GAF is not applied. Non-core sales include sales made under interruptible contracts, non-core contracts and off-system sales.

(13) **Non-Core Sales Margins** – The economic benefit derived from non-core transactions to which the GAF is not applied, including interruptible sales and other non-core sales generated from the use of the Company's Gas Supply resource portfolio.

(14) **Off-System Sales Margin** - The economic benefit derived from the non-firm sales of natural gas supplies upstream of Company's distribution system.

(15) **Number of Days Lag** - The number of days lag to calculate the purchased gas working capital requirement as approved by the Department.

(16) **Off-Peak Commodity** – Unless otherwise approved by the Department, the gas supplies assigned by the Company to serve firm load in the off-peak season.

(17) **Off-Peak Demand** - Unless otherwise approved by the Department, the gas supply demand and transmission capacity assigned by the Company to serve firm load in the off-peak season.

(18) **Off-Peak Period** - May through October.

(19) **Peak Commodity** - Unless otherwise approved by the Department, the gas supplies assigned by the Company to serve firm load in the peak season.

(20) **Peak Demand** - Unless otherwise approved by the Department, gas supply demand, peaking demands, storage and transmission capacity assigned by the Company to service firm load in the peak season.

(21) **Peak Period** - November through April.

(22) **PR Allocator** - The percentage allocated for the portion of annual capacity charges assigned to the seasons calculated in each CGA filing.

(23) **Pretax Weighted Cost of Capital** - The result of the calculation of the weighted cost of capital minus the weighted cost of debt, divided by one, minus the currently effective combined tax rate, plus the weighted cost of debt.

(24) **Purchased Gas Working Capital** - The allowable working capital derived from peak and off-peak, demand and commodity related costs.

COST OF GAS ADJUSTMENT CLAUSE

(25) **Tax Rate** is the combined State and Federal income tax rate.

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

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

6.0 Gas Adjustment Factor (GAF) Formula

The Gas Adjustment Factor ("GAF") Formula shall be computed on a semiannual basis using forecasts of seasonal gas costs, carrying charges, sendout volumes, and sales volumes. Forecasts may be based on either historical data or Company projections, but must be weather-normalized. Any projections must be documented in full with each filing.

A separate seasonal GAF will be computed for the combined Low Load Factor classes namely Rates R-3, R-4, G-40, G-41, G-42 and G-43; and for the combined High Load Factor classes namely Rates R-1, R-2, OL, G-50, G-51, G-52 and G-53. The calculation of each seasonal GAF utilizes information periodically established by the DTE. The table below lists the following approved cost factors as approved in D.T.E. 05-27:

Local Production & Storage Cost	\$7,430,587
LNG/LPG Production Cost included above	\$5,045,484
Bad Debt Expense Percentage	2.15%

Peak GAF Formula

The Peak GAF shall be comprised of a peak demand factor (DFp), a peak commodity factor (CFp), a peak production and storage demand factor (PSp), gas suppliers' refund factors (R1 and R2) defined in Section 8.00 and a bad debt factor (BDF) defined in Section 15.00, for the Company's High and Low Load Factor classes and calculated at the beginning of the peak season according to the following formula:

$$GAFp^x = DFp^x + PSp^x + CFp^x + BDF - R1 - R2$$

Peak Demand Factor (DFp) Formula

$$DFp^x = \frac{Dp^x - NCSMp^x - CECRCR}{P : Sales^x} + RFpd + WCFpd$$

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and:

$Dp^x = BASEDp^x + REMAINDp^x + PSp^x$

and:

$NCSMp^x = CRR^x + ISM^x + NTSM^x$

and:

RFpd = Rpd/P:Sales

and:

$$WCFpd = \frac{\dfrac{[(WCApd \times CC) - (WCApd \times CD)]}{(1 - TR)} + (WCApd \times CD) + WCRpd}{P : Sales}$$

and:

WCApd = Dp x (DL/365)

Where:

BASEDp	Peak period base use demand charges assigned on the basis of base use entitlements to low cost pipeline supplies using the average of July and August's daily loads.
CC	Weighted cost of capital as defined in Section 500.
CD	Weighted cost of debt as defined in Section 5.00.
CECRCR	Revenues from billing the Capacity Exempt Customer Reliability Charge.
CRR	The returnable Capacity Release Revenues allocated to the peak period. See Section 7.00.
DL	Number of days lag from the purchase of gas from suppliers to the payment by customers.
Dp	Demand Charges allocated to the peak period as defined in Section 5.00.
$NCSMp^X$	The sum of the returnable Interruptible Non-Core Sales Margins, the returnable Capacity Release Revenues and the Off-System margins.
ISM	The returnable Interruptible Sales Margins allocated to the peak period. See Section 7.00.
NTSM	The returnable Off-System Sales Margins allocated to the peak period. See Section 7.00.
P:Sales	Forecasted sales volumes associated with the peak period.

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REMAINDp	Peak period remaining use demand charges assigned to classes on the basis of their load's contribution to the design day load less their base use entitlements to pipeline supplies. This remaining capacity cost is allocated to seasons using the Proportional Responsibility (PR) allocator.
RFpd	Peak demand charge reconciliation adjustment factor per billed peak sales volume associated with demand charges related to the peak period.
Rpd	Reconciliation Costs - Peak demand deferred gas costs, Account 175.21 balance, inclusive of the associated Account 175.21 interest, as outlined in Section 9.00.
TR	Combined Tax Rate as defined in Section 5.00
WCApd	Demand charges allowable for working capital application as defined in Section 10.00.
WCFpd	Working Capital allowable factor per billed peak sales volume associated with demand charges allocated to the peak period as defined in Section 10.00.
WCRpd	Working Capital reconciliation adjustment associated with peak demand charges - Account 176.24 balance as outlined in Section 10.00.
x	Designates Load Factor Specific allocation of costs, based on Simplified Market Based Allocation factors as determined in the Company's most recent rate proceeding.
PSpx	Portion of test year Local Production Capacity and Storage Costs, as defined in Section 5.00, allocated to peak period firm sales through the CGAC as determined in the Company's most recent rate proceeding.

Peak Commodity Factor (CFp) Formula

$$CFp^x = \left[\frac{Cp^x - NCCCp^x + FC^x}{P : Sales^x} \right] + RFpc + WCFpc$$

and:

$$Cp^x = BASECp^x + REMAINCpx$$

and:

$$RFpc = Rpc / P{:}Sales$$

and:

$$WCFpc = \frac{\left[\frac{(WCApc \times CC) - (WCApc \times CD)}{(1 - TR)} \right] + (WCApc \times CD) + WCRpc}{P{:}\ Sales}$$

and:

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WCApc = Cp x (DL/365)

Where:

BASECp	Peak period base use commodity charges assigned on the basis of base use entitlements to low cost pipeline supplies using the average of July and August daily loads.
CC	Weighted costs of capital as defined in Section 5.00
CD	Weighted costs of debt as defined in Section 5.00.
Cp	Commodity Charges allocated to the peak period as defined in Section 5.00.
DL	Number of days lag from the purchase of gas from suppliers to the payment by customers.
FC	Inventory finance charges as defined in Section 5.00.
NCCCp	Non-Core Commodity Costs allocated to the peak period as defined in Section 5.00.
P:Sales	Forecasted sales volumes associated with the peak period.
REMAINCp	Peak period remaining use commodity charges computed as dispatched commodity costs less base use commodity costs.
RFpc	Peak commodity charge reconciliation adjustment factor per billed peak sales volume associated with commodity charges related to the peak period.
Rpc	Reconciliation Adjustment Costs - Account 175.23 balance, inclusive of the associated Account 175.23 interest, as outlined in Section 9.00.
R	Combined Tax rate as defined in Section 5.00.
WCApc	Commodity charges allowable for working capital application as defined in Section 10.00.
WCFpc	Working Capital allowable factor per peak sales volume associated with commodity charges allocated to the peak period as defined in Section 10.00.
WCRpc	Working Capital reconciliation adjustment associated with peak commodity charges Account 175.24 balance as outlined in Section 10.00.
x	Designates Load Factor class specific allocation of costs, based on Simplified Market Based Allocation factors, as determined in the Company's most recent rate proceeding.

Off-Peak GAF Formula

The Off-Peak GAF shall be comprised of an off-peak demand factor (Dfop) an off-peak production and storage demand factor (PSop), an off-peak commodity factor (Cfop), gas suppliers' refund factors (R1 and R2) defined in Section 8.00 and a bad debt factor (BDF), defined in Section 15.00 for the Company's High and Low Load Factor classes, and calculated at the beginning of the off-peak season according to the following formula.

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$$GAFop^{X} = DFop^{X} + CFop^{X} + PSop^{x} + BDF - R1 - R2$$

Off-Peak Demand Factor (DFop) Formula

$$DFop^{x} = \frac{Dop^{x}}{OP{:}Sales^{x}} + RFopd + WCFopd$$

and:

$$Dop^{X} = Sum{:}BLDop^{X} + (Sum{:}BLDXop^{X} \times (1 - PR))$$

and:

$$RFopd = Ropd / OP{:}Sales$$

and:

$$WCFopd = \frac{\dfrac{[(WCAopd \times CC) - (WCAopd \times CD)]}{(1 - TR)} + (WCAopd \times CD) + WCRopd}{(OP{:}Sales)}$$

and:

$$WCAopd = Dop\ (DL/365)$$

Where:

BLDop	Demand charges billed to the Company during the off peak period for the portion of base demand associated with serving base load requirements as defined in Section 5.00.
BLDXop	Base demand costs in excess of demand costs associated with base load level billed to the Company during the off-peak period.
CC	Weighted cost of capital as defined in Section 5.00.
CD	Weighted cost of debt as defined in Section 5.00
DL	Number of days lag from the purchase of gas from suppliers to the payment by customers.
Dop	Demand charges allocated to the off-peak period as defined in Section 5.00.
OP:Sales	Forecasted sales volumes associated with the off-peak period.

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PR	Proportional Responsibility Allocator - A percentage representing a portion of capacity/product charges incurred in the off-peak season and assigned to the peak period calculated in each CGA filing as defined in Section 5.0.
RFopd	Off-peak demand charge reconciliation adjustment factor per billed off peak throughput volume associated with demand charges related to the off peak period.
Ropd	Reconciliation Costs - Account 175.11 balance, inclusive of the associated Account 175.11 interest, as outlined in Section 9.00.
SMBA	Simplified Market Based Allocator – Load Factor specific allocator as defined in Section 5.00
TR	Combined Tax rate as defined in Section 5.0
WCAopd	Demand charges allowable for working capital application as defined in Section 6.1.
WCFopd	Working Capital factor allowable per billed off-peak sales associated with demand charges allocated to the off-peak period as defined in Section 10.0
WCRopd	Working Capital reconciliation adjustment associated with off-peak demand charges balance account 175.14 balance as outlined in Section 10.0.
x	Designates Load Factor specific allocation of costs based on Simplified Market Based Allocation factors, as determined in the Company's most recent rate proceeding.
PS_{op}^{x}	Portion of test year Local Production Capacity and Storage Costs, as defined in Section 5.00, allocated to off-peak period firm sales through the CGAC as determined in the Company's most recent rate proceeding.

Off-Peak Commodity Factor (CFop) Formula

$$CFop^{x} = \frac{Cop^{x} - NCCCop^{x}}{OP : Sales^{x}} + RFopc + WCFopc$$

and:

$$Cop^{X} = Sum{:}OPC^{X} - BOao^{X} - INJop^{X} - LIQop^{X}$$

and:

$$BOao^{X} = [(BOop - (BOvolop \times (TPop/TPvolop))) SMBA^{X}]$$

and:

$$RFopc = Ropc/OP{:}Sales$$

and:

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$$WCFopc = \frac{\dfrac{[(WCAopc \times CC)-(WCAopc \times CD)]}{(1 - TR)} + (WCAopc \times CD) + WCRopc}{OP:Sales}$$

and:

$$WCAopc = Cop \quad (DL/365)$$

Where:

BOao	LNG Boil-off allocation as defined in Section 9.00.
BOop	Cost of LNG Boil-off during the off-peak period.
BOvolop	LNG Boil-off volumes purchased in the off-peak period.
CC	Weighted cost of capital as defined in Section 5.00.
CD	Weighted cost of debt as defined in Section 5.00.
Cop	Commodity Charges billed to the off-peak period as defined in Section 5.00
DL	Number of days lag from the purchase of gas from suppliers to the payment by customers. See Section 10.00.
INJop	Injections into underground storage during the off-peak period.
LIQop	Liquefactions into storage during the off-peak period.
NCCCop	Non-core commodity costs allocated to the off-peak period as defined in Section 6.05.
OP:Sales	Forecasted sales volumes associated with the off-peak period.
OPC	Commodity charges associated with gas supply sent out in the off-peak season as defined in Section 5.00.
RFopc	Off peak commodity charge reconciliation adjustment factor per billed off peak sales volume associated with commodity charges related to the off-peak period.
Ropc	Reconciliation Adjustment Cost - Account 175.13 balance, inclusive of the associated Account 175.13 interest, as outlined in Section 9.00.
TPop	Total pipeline commodity purchase charges for the off-peak period.
TPvolop	Total pipeline purchase volumes for the off-peak period.
TR	Combined Tax rate as defined in Section 5.00.
WCAopc	Commodity charges allowable for working capital application as defined in Section 10.00.
WCFopc	Working Capital allowable per off-peak sales volume associated with commodity charges allocated to the off-peak period as defined in Section 10.00.
WCRopc	Working Capital reconciliation adjustment associated with off-peak commodity charges - Account 176.14 balance, as outlined in Section 10.00.
x	Designates Load Factor specific allocation of costs, based on Simplified Market Based Allocation factors.

COST OF GAS ADJUSTMENT CLAUSE

7.0 <u>Interruptible Sales, Off-System Sales and Capacity Release Revenues</u>

A threshold level of margins will be established annually and separately for Interruptible Sales, Off-System Sales and Capacity Release Revenues. Any margins earned in excess of the predetermined level shall be divided between the Company and its firm sales customers under a 25/75 sharing arrangement. The threshold level of margins shall be adjusted to reflect additions or losses from Customers who switch from FT, FS or Interruptible Transportation ("IT") to IS and conversely, from IS to FT, FS or IT. The Company shall adjust the threshold level annually to reflect Interruptible Sales, Off-System sales, and capacity release revenues for the twelve-month period ending April 30 of each year.

Margins from Interruptible Sales, Off-System Sales and Capacity Release will be reflected as separate credits in the peak season GAF and shall be calculated as the sum of the following:

(1) 100% of the margins earned up to the predetermined threshold level.

(2) 75% of the margins earned in excess of the predetermined threshold level.

8.0 <u>**Gas Suppliers' Refunds**</u> - Accounts 265.85 and 265.86

Refunds from upstream capacity suppliers and suppliers of gas are credited to Account 265.85, "Refund-November" if received during the months of March through August, and to Account 265.86 "Refund-May", if received during the months of September through February.

A refund program shall be initiated with each semiannual GAF filing and shall remain in effect for a period of one year. The balance in Account 265.85 shall be placed into a refund program with each November filing. The balance in Account 265.86 shall be placed into a refund program with each May filing. The total dollars to be placed into a given refund program shall be net of over/under-returns from expired programs plus refunds received from suppliers since the previous program was initiated. The Company shall track and report on all Account 265.85 and Account 265.86 activities. If during any twelve-month period commencing with the billing month of November for Account 265.85 and May for Account 265.86, the projected supplier refund factor is less than one-hundredth of a cent per therm ($0.0001), the respective supplier refund account balance shall be transferred into Account 175.26 or Account 175.16 for the November and May filings respectively.

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Gas Supplier's Refund Factors

R1 The per unit supplier refund associated with the Refund – May program. The following formula shall be used to calculate the R1 factor.

$$R1 = \frac{R1\$ + I}{A{:}Sales}$$

Where:

R1$ Ending balance in Account 265.86 "Refund – May"
I Total forecasted interest calculated on the R1$ balance computed at the consensus prime rate as reported in the *Wall Street Journal* based on a 365 day year.
A:Sales Forecasted annual firm sales volumes.

R2 The per unit supplier refund associated with the Refund – November program. The following formula shall be used to calculate the R2 factor.

$$R2 = \frac{R2\$ + I}{A{:}Sales}$$

Where:

R2$ Ending balance in Account 265.85 "Refund – November"
I Total forecasted interest calculated on the R2$ balance computed at the Federal Reserve Prime Rate based on a 365 day year.
A:Sales Forecasted annual firm sales volumes.

9.0 Reconciliation Adjustments – Other than Working Capital

(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.

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ii. Charges associated with transmission capacity procured by the Company to serve base load requirements in the peak season.
iii. Charges associated with upstream storage and transmission capacity procured by the Company to serve firm load in excess of base load requirements in the peak period, plus a reallocation of a portion of such charges incurred in the off-peak season to serve firm load.
iv. Charges associated with peaking, production and storage capacity to serve firm load in the peak season as determined in the test year of the Company's most recent rate proceeding and allocated to firm sales storage service.
v. Credits associated with Non-Core Sales Margins or economic benefits from capacity release, off-system sales for resale and interruptible sales margins allocated to the firm sales service.
vi. Credits associated with daily imbalance charges billed transportation customers in the peak period.
vii. Credits associated with Capacity Exempt Customer Reliability Charges billed to Capacity Exempt Customers in the peak period in accordance with M.D.T.E. No. 35, Section 13.12.
viii. Peak demand Carrying Charges as defined in Section 5.00.

(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.
ii. Credit non-core commodity costs assigned to non-core customers to which the CGAC does not apply, as defined in Section 6.06 (NCCCp).
iii. Inventory finance charges (FC).
iv. Peak commodity Carrying Charges as defined in Section 5.00.

(c) Capacity Costs Allowable Per Off-Peak Demand Formula shall be:
i. Charges associated with transmission capacity and product demand procured by the Company to serve base load requirements in the off peak season.
ii. Charges associated with transmission capacity and product demand procured by the Company to serve firm load in excess of base load requirements in the off-peak period
iii. Credits associated with daily imbalance charges billed transportation customers in the off peak period.
iv. Off-peak demand Carrying Charges as defined in Section 5.00.

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v. Other A & G and Acct. 851 charges associated with peaking production and storage capacity to serve firm load in the off-peak season as determined in the test year of the Company's most recent rate proceeding and allocated to firm sales storage service

(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 purchases in the off-peak period, less the cost of injections and liquefactions into storage.

ii. Credits associated with Non-core commodity costs from non-core sales to which the GAF is not applied, as defined in Section 5.00.

iii. Off-peak commodity Carrying Charges as defined in Section 5.00.

(2) **Calculation of the Reconciliation Adjustments**

Account 175 contains the accumulated difference between gas cost revenues and the actual monthly gas costs incurred by the Company. The Company shall separate Account 175 into Peak Demand (Account 175.21), Peak Production and Storage Demand (175.22), Peak Commodity (Account 175.23), Off-Peak Demand (Account 175.11), Off-Peak Production and Storage Demand (175.12) and Off-Peak Commodity (Account 175.13). Account 175.21 shall contain the accumulated difference between revenues toward capacity costs calculated by multiplying the Peak Demand Factor for the High and Low Load Factor classes, (DFp^X) times monthly firm sales volumes for High and Low Load Factor classes, and the total capacity costs allowable per the peak demand formula. Account 175.22 shall contain the accumulated difference between revenues toward gas costs as calculated by multiplying the Peak Commodity Factor for the High and Low Load Factor classes, (CFp^X) times monthly firm sales volumes for High and Low Load Factor classes, and the total commodity costs allowable per the peak commodity formula. Account 175.22 shall contain the accumulated difference between revenues as calculated by multiplying the Peak Production and Storage Demand Factor for the High and Low Load Factor class, (PS_p^x) times monthly firm sales volumes forthe High and Low Load Factor classes, and the total production and storage costs allowable per the peak production and storage demand formula. Account 175.11 shall contain the accumulated difference between revenues toward capacity costs calculated by multiplying the Off-Peak Demand Factor for the High and Low Load Factor classes,

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($DFop^X$) times monthly firm sales volumes for the High and Low Load Factor classes, and the total capacity costs allowable per the off-peak demand formula. Account 175.13 shall contain the accumulated difference between revenues toward gas costs as calculated by multiplying the Off-Peak Commodity Factor for the High and Low Load Factor classes, ($CFop^X$) times monthly firm sales volumes for the High and Low Load Factor classes, and the total commodity costs allowable per the off-peak commodity formula. Account 175.12 shall contain the accumulated difference between revenues as calculated by multiplying the Off-Peak Production and Storage Demand Factor for the High and Low Load Factor classes, (PS_{op}^x) times monthly firm sales volumes for the High and Low Load Factor classes, and the total production and storage costs allowable per the off-peak production and storage demand formula.

Carrying Charges as defined in Section 5.00 shall be added to each end-of-the-month balance. The peak demand reconciliation adjustment factor (RFpd) shall be determined for use in the peak GAF calculation by dividing the peak demand account (175.21) balance as of the peak reconciliation date, by the forecasted sales volume associated with the peak period. The peak production & storage demand reconciliation adjustment factor (RFppsd) shall be determined for use in the peak GAF calculation by dividing the peak production and storage demand account (175.22) balance as of the peak reconciliation date, by the forecasted sales volume associated with the peak period. The peak commodity reconciliation adjustment factor (RFpc) shall be determined for use in the peak GAF calculation by dividing the peak commodity account (175.23) balance as of the peak reconciliation date, by the forecasted sales volume associated with the peak period. The off-peak demand reconciliation adjustment factor (RFopd) shall be determined for use in the off peak GAF calculation by dividing the off-peak demand account (175.11) balance as of the off-peak reconciliation date, by the forecasted sales volume associated with the off-peak period. The off-peak production and storage demand reconciliation adjustment factor (RFoppsd) shall be determined for use in the off-peak GAF calculation by dividing the off-peak production and storage demand account (175.12) balance as of the off-peak reconciliation date, by the forecasted sales volume associated with the off-peak period. The off-peak commodity reconciliation adjustment factor (RFopc) shall be determined for use in the off-peak GAF calculation by dividing the off-peak commodity account (175.13) balance as of the off-peak reconciliation date, by the forecasted sales volume associated with the off-peak period.

The peak period reconciliation will be filed thirty (30) days prior to the peak period GAF filing, which is seventy-five (75) days prior to the effective date.

The off-peak period reconciliation shall be filed thirty (30) days prior to the off-peak period GAF filing, which is seventy-five (75) days prior to the effective date.

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10.0 Working Capital Reconciliation Adjustments

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

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

i. Charges associated with upstream storage, transmission capacity, and product demand procured by the Company to serve firm load in the peak season.
ii. Charges associated with transmission capacity procured by the Company to serve base load requirements in the peak season.
iii. Charges associated with upstream storage and transmission capacity procured by the Company to serve firm load in excess of base load requirements in the peak period, plus a reallocation of a portion of such charges incurred in the off-peak season to serve firm load.
iv. Carrying Charges

(b) Working Capital 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 costs 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 liquefactions into storage.
ii. Non-Core Commodity Costs associated with non-core sales to which the GAF is not applied.
iii. Carrying charges.

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

i. Charges associated with transmission capacity procured by the Company to serve base load requirements in the off peak season.
ii. Charges associated with upstream storage and transmission capacity procured by the Company to serve firm load in excess of base load requirements in the off-peak period.
iii. Carrying charges.

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

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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 purchases in the off-peak period, less the cost of injections and liquefactions into storage.
ii. Non-core commodity costs associated with non-core sales to which the GAF is not applied, as defined in section 6.05.
iii. Carrying charges.

(2) The peak and off-peak, demand, and commodity 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.

(3) The peak and off-peak, demand, and commodity working capital allowances shall each be calculated by applying the Company's weighted cost of capital to each working 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 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) Calculation of the Reconciliation Adjustments

Accounts 175.14, 175.13, 175.24, and 175.23 contain the accumulated difference between working capital allowance revenues and the actual monthly working capital allowance costs as calculated from actual monthly costs for the Company plus Carrying Charges as defined in Section 5.00.

The components of the Company's purchased gas days lag shall be recalculated each season based upon actual CGAC seasonal data. This recalculated days lag will be used in the calculation of the working capital allowance revenues. Each Account 175 shall contain the accumulated difference between revenues toward the working capital allowance and the working capital allowance.

The peak demand working capital reconciliation adjustment shall be determined for use in the peak demand factor calc ulations incorporating the peak demand working capital account 175.14 balance as of the peak reconciliation date designated by the Company. A peak commodity working capital reconciliation adjustment shall be determined for use in

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the peak commodity factor calculations incorporating the peak commodity working capital account 175.13 balance as of the peak reconciliation date designated by the Company. An off-peak working capital reconciliation adjustment (WCRopd) shall be determined for use in the off -peak demand factor calculations incorporating the off-peak demand working capital account (175.24) balance as of the off-peak reconciliation date designated by the Company. An off-peak commodity working capital reconciliation adjustment (WCRopc) shall be determined for use in the off-peak commodity working capital account (175.23) balance as of the off-peak reconciliation date designated by the Company.

11.0 Application of GAF to Bills

The Company will employ the GAFs as follows: The peak season rates to each Load Factor class shall be calculated by adding the respective peak demand factor and the peak commodity factor. The off-peak season rates to each Load Factor class shall be calculated by adding the respective off-peak demand factor and the off-peak commodity factor. The GAFs ($/therm) for each Load Factor class for each season shall be calculated to the nearest one-hundredth of a cent per therm ($0.0001) and will be applied to each customer's monthly sales volume within the corresponding Load Factor class.

12.0 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 Company's standardized forms approved by the Department. Required filings include 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 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.

13.0 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

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amended GAF filing must be submitted 10 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 GAF.

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

14.0 Customer Notification

The Company will design a notice, which explains in simple terms to customers the GAF, the nature of any change in the GAF and the manner in which the GAF is applied to the bill. 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.

15.0 Bad Debt Allowance

15.01 Purpose

The purpose of this provision is to establish a procedure that, subject to the jurisdiction of the Department, allows Bay State to adjust, on a semi-annual basis, its rates for the recovery of Bad Debt Expense

15.02 Bad Debt (BDF) Formula

The Bad Debt (BDF) Formula shall be computed on an annual bas is using forecasts of bad debt expense associated with gas costs, gas costs, carrying charges, sales volumes, and a working capital allowance. Forecasts may be based on either historical data or Company projections, but must be weather-normalized. Any projections must be documented in full with each filing. The forecast of bad debt expense associated with gas costs shall be based on the Company's projected gas costs in the respective seasonal GAF filings and the percent of net write-offs to total firm revenues as determined in the Company's last rate proceeding.

The calculation at the beginning of the off-peak season shall be on a projected annual basis. The calculation at the beginning of the peak season will update the remaining months of the projected annual period with actual bad debt expenses and collections for the available months and projections for the remaining months of the annual period. The following formula shall be used to calculate the Bad Debt factor.

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$$BDF = \frac{BD + RAbd + WCbd}{A{:}Sales}$$

and:

$$WCbd = \frac{(WCAbd * CC) - (WCAbd * CD)}{(1 - TR)} + (WCAbd * CD)$$

and:

$$WCAbd = BD * (DL/365)$$

Where:

A:Sales	Forecast annual sales volumes.
BD	Forecast Bad Debt Expense as defined in Section 5.00; derived by multiplying the forecast annual gas costs by the percent of annual net write-offs to annual firm revenues as determined in D.T.E. 05-27.
CC	Weighted cost of capital as defined in Section 5.00.
CD	Weighted cost of debt as defined in Section 5.00.
DL	Number of days lag from the purchase of gas from suppliers to the payment by customers.
RAbd	Bad Debt Expense reconciliation adjustment - Account 175.31 balance.
TR	Combined Tax rate as defined in Section 5.00.
WCAbd	Bad Debt allowable for working capital application defined as the costs associated with the gas cost portion of bad debt incurred by the Company to serve firm load.
WCbd	Working Capital Allowance associated with the gas portion of bad debt for the period including the Pretax Weighted Cost of Capital as defined in Section 5.00.

15.03 Bad Debt Reconciliation Adjustment

Account 175.31 shall contain the accumulated difference between the annual revenues toward bad debt, as calculated by multiplying the bad debt factors (BDF) times monthly firm sales volumes, and the annual allowed Bad Debt expenses, allowed working capital on Bad Debt and Carrying Charges as defined in Section 5.00.

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An annual bad debt reconciliation adjustment (RAbd - as defined in Section 15.02) shall be determined for use in the bad debt factor calculations incorporating the bad debt working capital account (175.32) balance as of the reconciliation date designated by the Company.

(a) Costs Allowable per Bad Debt Formula shall be:
  i. Un-collectable gas costs incurred by the Company to serve firm sales load, as determined by deriving the portion of actual net write-offs associated with gas cost collections.
  ii. Account 175.32 – Bad Debt, Carrying Charges.
  iii. Working Capital Gas Costs Allowable per Bad Debt Formula, which shall be charges associated with bad debt incurred by the Company to serve firm sales load and applied to the working capital formula.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

DIRECT TESTIMONY OF JOSEPH A. FERRO

FOR
BAY STATE GAS COMPANY

EXHIBIT BSG-1

D.T.E. 05-27

MARCH 31, 2006

DIRECT TESTIMONY OF
JOSEPH A. FERRO

I. INTRODUCTION

Q. Please state your name, affiliation and business address.

A. My name is Joseph A. Ferro. I am Manager, Regulatory Policy for Bay State Gas Company ("Bay State" or the "Company"). My business address is 300 Friberg Parkway, Westborough, Massachusetts 01581.

Q. Are you the same Joseph A. Ferro that provided evidence before the Department of Telecommunications and Energy ("Department") in D.T.E. 05-27?

A. Yes, I am. I provided testimony relative to revenues, rate design and tariff issues. Exh. BSG-JAF-1; Exh. BSG-JAF-2; and, Exh. BSG-JAF-3.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is to provide the Department with a proposal that addresses the operational risks associated with transportation customers that are exempt from the Department's mandatory capacity assignment rules, i.e. "Grandfathered[1]" customers. My testimony incorporates and responds to the

[1] Customers acquire Grandfathered status in one of two ways. All customers taking firm transportation service as of February 1, 1999, the date the Department adopted mandatory capacity assignment, had the option of continuing to take firm transportation service without accepting assignment of capacity. In addition, any customer that takes firm transportation service from Bay State without first taking firm sales service would be afforded a capacity assignment exemption. Customers lose their Grandfathered exemption if they elect to be served under a firm sales service in the future.

Department's findings on this matter in previous proceedings. In D.T.E. 05-27, the Department directed Bay State to submit for Department review a complete proposal for monitoring overtakes by grandfathered transportation customers that addresses the directives in D.T.E. 02-75-A. Bay State Gas Company, D.T.E. 05-27, p. 356 (2005). The directives in D.T.E. 02-75-A require Bay State to, inter alia, submit a report to the Department explaining how it could implement a system under which the Company would have the ability to monitor usage by its Grandfathered customers and shut-off any customer that overtakes on a critical day.

My testimony describes the substantial questions concerning the system outlined by the Department raised during Bay State's investigation of its feasibility, including the system's overall cost, operational limitations and increased liability associated with shutting off customers. Therefore, I am also presenting an alternative proposal that meets the Department's criteria for a permanent resolution of the reliability risks associated with Grandfathered loads.

Q. Do grandfathered loads pose reliability risks to the firm service Bay State provides to all firm customers?

A. Yes. Bay State requires deliveries from upstream pipelines in order to maintain reliability. For firm sales and firm non-grandfathered customers, Bay State acquires primary firm upstream capacity to ensure that it is able to maintain reliability. By virtue of the fact that there is no Bay State primary firm capacity rights associated with Grandfathered transportation loads, Bay State is subject to operational risks in the event that these customers take unauthorized volumes on a critical day. The potential harm created by such action cannot be limited to Grandfathered customers due to the integrated nature of Bay State's system operations.

Q. **Please describe the Department's review of previous Bay State proposals to address the operational risks associated with Grandfathered customers.**

A. In D.T.E. 02-75, Bay State proposed to implement a ten percent contingency reserve in its planning process as an overall planning framework to address both the operational risks associated with Grandfathered loads and the potential for wholesale market disruptions that are not reflected in the Company's design weather planning standards. The Department disagreed with Bay State's proposal due to concerns regarding the shifting of costs from Grandfathered customers to other transportation and sales customers. While rejecting Bay State's proposal, the Department agreed that Grandfathered customers pose operational risks, which led it to direct Bay State to monitor overtakes by Grandfathered customers and take actions to shut them off. The Department also required Bay State to notify all Grandfathered customers that they were subject to potential shutoff.

Q. **How did Bay State follow the Department's directives in D.T.E. 02-75-A?**

A. Bay State notified all grandfathered customers that they were subject to potential shutoff on January 31, 2005. A copy of the letter notification is provided as

Exhibit BSG-1, Attachment JAF-1. In addition, Bay State investigated the proposed system of monitoring grandfathered customer overtakes, which would be followed by physical disconnection. During D.T.E. 05-27, Bay State incorporated its proposal to address the problem by assigning capacity to Grandfathered customers responsible for unauthorized overtake. The Department rejected Bay State's proposal, indicating that it was incomplete in that it did not address the proposed system monitoring of Grandfathered customer overtakes.

Q. **Please discuss the results of Bay State's investigation of the proposed monitoring and disconnection system recommended by the Department.**

A. The system outlined by the Department, while not without merit, would require both facility upgrades and changes to the Bay State processes that govern daily protocols and interactions with Grandfathered customers and their suppliers. The facility requirements would mandate enhanced metering and flow control at grandfathered customer locations. Modified processes would need to provide for enhanced monitoring of competitive supplier scheduling activities on pipelines serving Bay State as well as new protocols for disconnecting grandfathered customers.

As Bay State investigated the requirements of a system that satisfies the Department's requirements, a number of areas of concern were identified that questioned its overall efficacy. Among these were the costs to customers of the advanced required metering equipment, inconsistencies with upstream pipeline scheduling flexibility and additional risk of customer confusion and aggravation, leading to ill will and possible court action.

Q. Please describe the required metering investments and the associated costs that would be required under the Department's proposal.

A. In order to shutoff grandfathered customers, Bay State requires either the ability to get on-site to ensure a physical shutoff or it must install remote load-control equipment.

Use of Bay State personnel to perform the physical shutoffs of multiple grandfathered customers of a non-performing supplier would be impractical. In the critical emergency event of an overtake in multiple locations, the time required to complete a physical shutoff, the geographic distance between customers in a supplier's pool, and the demands on resources needed to serve firm customers during periods of critical operations make such a diversion of resources completely inappropriate.

The only feasible method would be the installation of remote load-control equipment at grandfathered customer locations. However, only a limited number of vendors offer remote load control equipment of the type that would be required by Bay State. The capital costs of purchasing and installing this equipment would be approximately $17,000 to $25,000 per customer, which would result in approximately $35 million of total capital costs for the entire system. In addition to the upfront costs, Bay State would incur O&M costs, however, these are difficult to estimate because Bay State does not have direct experience with operating and maintaining this type of equipment.

Q. **Who would bear the cost of these advanced metering systems?**

A. The additional cost should be recovered from the customers who created the cost, resulting in an increase in the monthly customer charge for grandfathered customers. Applying the Company's approved pre-tax return of 11.71% and its depreciation rate for meters of 3.96% to an average incremental metering investment of $20,000 yields a total annual cost of approximately $3,134. This translates into an increased customer charge of approximately $260 per month, or a 100% - 400% increase over existing monthly charges.

Q. **Are there additional system or operational difficulties associated with establishing a system for physically shutting off customers that overtake on an unauthorized basis on a Critical Day?**

A. Yes. In order to prepare to shutoff any particular grandfathered customer taking gas on an unauthorized basis, existing nomination and balancing protocols would need to be modified to require suppliers to nominate on a customer-specific basis. This approach, however, would eliminate many of the benefits the supplier obtains when pooling customer loads. Alternatively, suppliers could be required to provide a predetermined allocation along with their daily nomination that specifies which customers should be allocated any under-delivery that occurs.

This, however, represents a significant increase in nomination and balancing complexity.

More importantly, scheduling flexibility inherent in the North American Energy Standards Board's rules inhibits the ability to timely identify an unauthorized overtake. Scheduling shortfalls at the beginning of the Gas Day at 10 a.m. Eastern time can be made up by intraday nominations made at 6 p.m. Eastern time, permitting shippers to receive their full volumes beginning at 9 p.m. Eastern time. through the end of the Gas Day. For its part, Tennessee Gas Pipeline, a long-haul feed to Bay State's city gate comprising a significant proportion of Bay State's resource portfolio, offers even greater flexibility by allowing shippers to schedule volumes up until one hour prior to the end of the Gas Day. Bay State cannot shutoff a customer until all intraday nomination deadlines have passed. The timing of intra-day nominations and even customer usage patterns renders this shut-off-based approach deficient. By the time an incident can be identified, it is too late. The physical service disruptions would have already been suffered. Further, if unauthorized use by grandfathered customers resulted in overtakes by Bay State of its allowed pipeline quantities as point operator, Bay State would be further subject to penalties and additional liabilities if service to other pipeline shippers was thereby impaired.

Q. What do you expect would be the impact on customers under the proposal outlined by the Department in D.T.E. 02-75A?

A. The changes required by implementing the proposed monitoring and shutoff system would have a material impact on customers. Customers will be required to bear additional costs imposed by Bay State to cover the costs of required facilities and may also be required to pay incremental costs incurred by competitive suppliers to compensate for additional risks and penalties that may be incurred. In addition to the cost impacts of the system, the risk of shutoff could eliminate the viability of a customer retaining its Grandfathered status. This is particularly true for essential needs customers, which represent almost fifty percent of Bay State's Grandfathered customers. Bay State anticipates that there would be a groundswell of opposition among Grandfathered customers upon learning that Bay State would be installing flow-control equipment. This is particularly true for essential needs customers.

Q. Would the Company expect to have any other problems with physically shutting off customers?

A. Even with tariff provisions authorizing the Company to remotely shutoff Grandfathered customers who overtake, the Company would anticipate that such an unanticipated shutoff could result in damages to customers in the form of a loss of product or damage to equipment. If such consequences of a shutoff occurred, the Company could expect customers filing to hold the Company liable for their loss or petitioning the Department or the Governor's Office to continue to receive gas service.

Taking into consideration the impacts on Grandfathered customers, the imposition of cumbersome nomination changes for suppliers and the operational and liability concerns discussed previously, Bay State recommends that the Department consider an alternative means of resolving this matter. Bay State believes that the new approach outlined in the remainder of my testimony appropriately addresses the operational implications of unique level of Grandfathered loads on Bay State's system in a manner that is consistent with the Department's earlier findings on this issue.

Q. Please describe Bay State's proposal for planning criteria that satisfies the problem of overtakes by grandfathered customers.

A. Bay State's proposed new incremental capacity planning standard is based solely on the level of grandfathered load on its system. Specifically, Bay State proposes to maintain access to capacity sufficient to meet thirty percent of the design day requirements of grandfathered loads on its system at any given point in time. The planning standard would translate into a level of required capacity that would substantially limit the increased operational risks of grandfathered supply service, which are significantly greater than any risks that Bay State's own system supply service presents. The costs of the capacity relied upon to meet this planning standard would be recovered solely from grandfathered customers through a charge whose revenues are credited to Bay State's Cost of Gas Adjustment ("CGA"). The capacity utilized by Bay State to meet the new planning standard would be sold in secondary markets when it is not utilized by Bay State, mitigating the overall cost of maintaining the new planning standard.

In addition, Bay State proposes to implement improvements to its existing reporting, relying primarily on existing systems and equipment installed on daily-metered customers, that will enable it to more closely monitor the occurrence of daily overtakes so that corrective action can be taken quickly. Changes to Bay State's nominating and balancing protocols will enable Bay State to acquire data necessary to establish unauthorized overtakes on a customer-specific basis. These reporting protocols are far more cost effective than installing the flow control equipment I discussed earlier.

The changes to the nomination and balancing protocols would not allow Bay State to monitor the daily overtakes of specific non-daily metered grandfathered customers. These customers represent approximately one-half of the Grandfathered population on Bay State's system, but only ten percent of the load. In lieu of monitoring the specific usage of non-daily metered customers, Bay State proposes to establish the occurrence of unauthorized overtakes using its existing system of comparing required supplier nominations to actual supplier deliveries. To the extent that the Department is concerned with this element of Bay State's monitoring proposal, it could require Bay State to switch all existing non-daily metered grandfathered customers to daily-metered service or forego grandfathered status via the assignment of capacity to their supplier.

Q. How did Bay State determine that the thirty percent planning standard is appropriate?

A. The thirty percent capacity reserve level is based upon a combination of analytical results and reasoned business and operational judgment. Bay State reviewed the historic performance of competitive suppliers serving daily-metered grandfathered customers over the period November 2001 through December 2005. The results of this review indicate that Bay State experienced substantial delivery failures on a number of days during this period. Exhibit BSG-1 at Attachment JAF-2 provides analysis of the top daily supplier overtakes during the period. These data indicate that on three occasions in the four-year period, supplier overtakes exceeded thirty percent in one of the Company's divisions. This is a very high incidence rate compared to the Bay State's one-in-twenty-five-year planning standards applicable to design weather. Moreover, these data are post-imbalance trading whereby a supplier could reduce its overtake by trading with a supplier that had an undertake on the same day. The observed level of overtakes would have been even greater if daily imbalance trading had been excluded. The primary concern with unauthorized overtakes by grandfathered customers is the possibility that they may occur on a design day when Bay State's resources are fully utilized and upstream pipelines are stressed. Bay State did not experience a design day during the analysis period, however, many of the most significant overtakes occurred on cold-weather days when pipeline operations are typically more constrained and secondary deliveries are more likely to be curtailed.

A final factor that Bay State considered was the allocation of risk across suppliers serving its Grandfathered customers. Presently, 9 suppliers have Grandfathered customers in their pools; customer design day load ranging from less than 1 Dth to 2,248 Dth and pools ranging in size from 27 to 8,533 Dth of design day load. The thirty percent of the 58,846 Dth of design day load of all Grandfathered customers, or 17,654 Dth, would cover performance failures by the 22 largest Grandfathered customers of these suppliers. While Bay State would not be able to redress the concurrent failure of all supplies to Grandfathered customers, the Company believes that the vast majority of the existing operational risk would be mitigated under its proposal.

Q. **How will the new planning standard affect Bay State's resource planning process?**

A. Presently, Bay State analyzes its resource needs on the basis of the design weather requirements of its sales and non-grandfathered transportation customers. The implementation of the new planning standard would contribute to a resource need applicable to a limited portion of the requirements of Grandfathered transportation customers in addition to Bay State's other resource needs. This need would be factored into Bay State's integrated resource planning process increasing the quantity of capacity necessary to maintain reliable service. The costs of the incremental capacity would be borne by Grandfathered customers. Based on existing levels of Grandfathered customer loads, the incremental planning standard would translate into a capacity need of 17,654 Dth.

Q. **Once the reserve capacity is in place, are there any consequences for specific customers that fail to deliver?**

A. Yes. Bay State recommends that customers who demonstrate that they have not acquired sufficiently reliable service be subject to future assignment of capacity. In particular, any Grandfathered customer that experiences an unauthorized overtake that exceeds thirty percent on a critical operating day would be subject to permanent assignment of capacity. This provides an important incentive for customers to ensure that their suppliers are able to provide reliable service. Limiting the assignment to overtakes that exceed thirty percent on critical days reflects the capacity acquired to satisfy the thirty percent reserve and further protects customers from the potential consequences associated with under-deliveries by suppliers of their requirements on the majority of days during the year. Finally, permanently assigning capacity to customers who overtake by greater than 30% and removing their requirements from the basis of determining the cost of the thirty percent reserve, more directly addresses the cost imposition of certain customers within the Grandfathered group.

Q. **Have you prepared an estimate of the cost impact of Bay State's proposal?**

A. Yes. Exhibit BSG-1 at Attachment JAF-3 provides a sample calculation of the impact of Bay State's proposal. The aggregate Grandfathered peak load on Bay State's system is currently 58,846 Dth. The annual cost of the capacity required to satisfy the thirty percent planning standard is $2.3 million based on the average capacity cost of Bay State's existing portfolio. This translates into a charge of $0.182 per Dth based on Bay State's proposal to recover the full costs from grandfathered customers. To the extent that the size of the pool of grandfathered loads increases or decreases, the charge should remain relatively stable as the level of capacity associated with the planning standard will adjust commensurately.

Q. What are the benefits to customers of Bay State's proposed permanent resolution to the issues created by Grandfathered loads?

A. The primary benefit of Bay State's proposal is that it allows Grandfathered customers to continue to enjoy the financial benefits of firm transportation service exempt from capacity assignment requirements.

While Grandfathered customers would bear additional cost under the new planning standard, the impact on the total cost of firm gas service would be approximately 0.6% ($2.3 m / $400 m). Compared with the benefits that these customers realize under Grandfathered status, the cost is far less than would be required under the implementation of an alternative system based on the installation of load control equipment. Moreover, it eliminates the risk of shutoff to an important class of customers that are required to meet essential needs and those whose operations support the Massachusetts economy. Depending on the circumstances, the new planning standard may ease the difficulty with which Grandfathered customers may return to sales service.

Q. Are tariff modifications appropriate to implement Bay State's proposal?

A. Yes. Bay State has revised the capacity assignment provisions of Section 13 of M.D.T.E. No. 35, to incorporate the changes associated with its proposal. Specifically, Section 13.12 has been added to recover the costs associated with the planning standard from Grandfathered transportation customers. In addition Section 13.13 has been added to specify the methodology Bay State will employ to monitor Grandfathered customer overtakes on Critical Days. Required tariff changes to the CGAC provide for the crediting of all revenues recovered from Grandfathered customers pursuant to the new charge reflected in Section 13.12 to gas costs recoverable from other customers.

Red-lined tariff pages providing all of the required changes to implement the proposal are provided as Exhibit BSG-1 at Attachment JAF-4.

Q. Why are the new resource planning standard and proposed tariff changes in the public interest?

A. Bay State's proposal is fair and equitable to Grandfathered customers as well as other firm customers: the increased costs of the new planning standard will be borne by Grandfathered customers eliminating the possibility of cost shifting. The associated cost increases to Grandfathered customers are reasonable in view of the benefits these customers receive, including the exemption from mandatory capacity assignment. The cost impact of Bay State's proposal is lower than any feasible alternative approach that would entail the installation of load control equipment at customer locations.

Q. **When should the proposal be implemented?**

A. Modified Terms and Conditions should be implemented September 1st of this year to allow Bay State to align its portfolio with the planning standard and reflect the impact in both its Peak Period Cost of Gas Adjustment filing on September 15, 2006, and in the IRP filing to be submitted by October 22, 2006.

Q. **Does this conclude your testimony?**

A. Yes, it does.

[DATE]

«ORG_NAME______________________________»
«FIRST_NAME______________» «LAST_NAME_______________»
«MAIL_ADDR______________________________»
«MAIL_CITY_______________», «ST2» «ZIP______________________»

Re: Customer account «CUST_ACCT»serving
«SERV_ADDR______________________________»,
«SERV_CITY_______________», «ST1»

Dear Customer:

On October 22, 2004, the Department of Telecommunications and Energy ("Department") issued its order clarifying certain issues related to Bay State Gas Company's ("Bay State's") continuing provision of service to its firm transportation customers who have not been assigned the Company's capacity associated with meeting the respective customers' daily requirements ("grandfathered"). Bay State Gas Company, D.T.E. 02-75-A (Oct. 22, 2004). The Department directed the Company in that order to notify you, as a grandfathered customer under the above-referenced account, of certain conditions under which Bay State should continue to provide service to grandfathered customers. Since this letter is likely being addressed to the billing contact of your company, I suggest that it be forwarded to the energy decision maker at your company, as well to your company's natural gas supplier.

In that October 22, 2004 order, the Department identified that it was necessary for the Department to establish a plan for Bay State to address the operational risks posed by the unauthorized taking of natural gas by Bay State's grandfathered firm transportation customers. Such unauthorized use of gas by a grandfathered customer essentially demonstrates a failure to have sufficient gas supply for that customer's use on certain days of the year, and imposes a risk that such gas use will cause Bay State's capacity reserved for its firm bundled sales and non-grandfathered customers to be insufficient. The Department required Bay State to notify and remind all of its grandfathered customers that unauthorized overtakes are subject to penalties pursuant to the Company's Terms and Conditions. The Department also directed the Company to notify you that such overtakes may threaten the integrity of Bay State's distribution system, and therefore could result in disconnects from the system.

Accordingly, please be advised and reminded that, as a grandfathered firm transportation customer of Bay State, you, or your supplier on behalf of you, must have sufficient natural gas to meet your daily requirements, and pursuant to state tariff provision, Bay State may assess penalties on any unauthorized use in the amount of five (5) times the daily index price of natural gas on the day of the overtake.

Please be aware that each time you take more natural gas from Bay State's distribution system than that which is being provided by your supplier, such overtake may threaten the integrity of Bay State's distribution system and jeopardize Bay State's ability to serve its bundled firm residential and commercial customers with natural gas service for heating and other needs. Accordingly, Bay State has an obligation to its other firm customers and the right, and specifically reserves the right, to shut off your meter and disconnect your service from its distribution system in the event of an overtake on any day of the year, especially during peak demand periods, or for any other reason it determines the operation of its distribution system may be jeopardized.

Please be further advised that, in order to alleviate the risk of system disruption as a result of the actions (i.e. the unauthorized use of natural gas) by Bay State's grandfathered customers, the Department has directed Bay State to implement a system under which Bay State will have the ability to monitor your gas usage on a daily basis to mitigate this potential risk of system disruption and submit a report to the Department, explaining how this system will work. We welcome input from you and your supplier on how best to accomplish this goal.

This notice is provided pursuant to the requirements of the Department's order in D.T.E. 02-75.

Since your marketer is aware that they need to supply your full gas requirements and should understand the potential ramifications of inadequate deliverability to the Company's system, a copy of this letter has been provided to them for reference. Please direct any questions about your current supply of natural gas to your marketer.

Please do not hesitate to call 1-877-777-3753 with any questions you may have about this letter or the Department order in D.T.E. 02-75.

Very truly yours,
Bay State Gas

Daily Metered Overtakes

	Brockton		Springfield/Lawrence		Over-Delivered	Combined
Date	Dth	%	Dth	%	Pools	Overtake
12/10/2001	447	6.5%	5,556	33.0%	(69)	5,933
11/5/2001	2,937	44.0%	2,676	14.7%	(1)	5,612
12/9/2001	485	7.7%	4,271	31.8%	(175)	4,581
2/11/2002	831	11.2%	3,581	15.6%	(45)	4,367
2/5/2002	975	11.8%	3,519	16.5%	(110)	4,383
2/13/2002	179	12.8%	4,355	17.5%	(215)	4,319
12/1/2002	601	9.4%	3,097	18.0%	457	4,155
4/23/2002	521	9.9%	3,324	20.0%	(75)	3,769
12/4/2001	336	28.7%	3,825	25.3%	(518)	3,643
4/29/2002	717	12.8%	2,681	15.6%	(19)	3,379
4/24/2002	781	14.4%	2,634	16.5%	(39)	3,376
12/6/2004	482	9.7%	2,725	16.6%	(11)	3,197
2/14/2002	229	3.3%	3,004	14.0%	(186)	3,046
3/31/2003	580	11.6%	2,395	12.6%	(64)	2,910
12/2/2001	45	14.7%	3,506	25.4%	(654)	2,897
4/22/2002	665	11.0%	2,222	14.8%	(6)	2,880
11/29/2001	124	22.8%	3,144	18.3%	(423)	2,844
11/12/2001	1,309	16.8%	2,068	17.8%	(542)	2,835
4/28/2002	935	20.5%	1,912	14.8%	(20)	2,828
12/16/2001	1,289	22.1%	1,527	10.4%	(19)	2,798

Capacity Exempt Customer Reliability Charge
Example Calculation

Row	Description		Amount		Calculation
(1)	Capacity Exempt Customer Peak Day		58,846	Dth	
(2)	Average Annual Unit Capacity Cost		131.81	per Dth	
(3)	Factor		30%		
(4)	Reliability Costs	$	2,326,947		(1) x (2) x (3)
(5)	Capacity Release / OSS Margin Revenues	$	(6,407,187)		
(6)	Total System Design Day		504,151	Dth	
(7)	Capacity Release / OSS Credit	$	(747,866)		(5) x ((1) / (6)
(8)	Prior Period Under / (Over) Recovery	$	-		
(9)	Total CECRC Allowable Costs for Period	$	1,579,082		(4) + (7) + (8)
(10)	Capacity Exempt Customer Throughput (Therms)		86,722,280		
(11)	CECRC Charge per therm	**$**	**0.0182**		(9) / (10)

BAY STATE GAS COMPANY

M.D.T.E. No. 35
Cancels M.D.T.E. No. 2

DISTRIBUTION AND DEFAULT SERVICE TERMS AND CONDITIONS

Section

DISTRIBUTION AND DEFAULT SERVICE TERMS AND CONDITIONS

2.0 DEFINITIONS

Adjusted Target Volume ATV	The volume of Gas determined pursuant to Section 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.
Authorization 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.

DISTRIBUTION AND DEFAULT SERVICE
TERMS AND CONDITIONS

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.
Capacity Exempt Customer	Any Customer receiving Distribution Service whose TCQ is equal to zero as provided for in either Section 13.3.3 or Section 13.3.5 of these Terms and Conditions.
City Gate	The interconnection between a Delivering Pipeline and the Company's distribution facilities.
Company	____________________
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 19.0 of these Terms and Conditions, a Day declared at any time by the Company in its reasonable discretion when unusual operating

DISTRIBUTION AND DEFAULT SERVICE
TERMS AND CONDITIONS

	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 MDTE approves a suitable replacement.
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.
Default Service	Gas commodity service provided to a Customer who is not receiving Supplier Service, in accordance with Section 15.0 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.
Dekatherm	Ten Therms.

DISTRIBUTION AND DEFAULT SERVICE TERMS AND CONDITIONS

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.
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 25.0 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.
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.

DISTRIBUTION AND DEFAULT SERVICE TERMS AND CONDITIONS

Gas Service Area	An area within the Company's distribution system as defined in Section 4.0 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.
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 17.0 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 Suppliers' Peaking Service Account pursuant to Section 16.0 of these Terms and Conditions shall be equal to the sum of the Customers' MDPQs in a Supplier's Aggregation Pool.
MDTE	The Massachusetts Department of Telecommunications and Energy.
Month	A calendar month of Gas Days.
Monthly Index	The average of the Daily Indices for the relevant Month.

DISTRIBUTION AND DEFAULT SERVICE TERMS AND CONDITIONS

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, and other such non-confidential information as may be reasonably required by the Company.
Off-Peak Season	The consecutive months May to October, inclusive.
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 19.0 of these Terms and Conditions.
Peak Day	The forecasted Gas Day during which the Company's system experiences the highest aggregate Gas Usage as approved by the MDTE.
Peaking Capacity	Capacity normally used by the Company to provide Peaking Service.
Peak Season	The consecutive months November to April, inclusive.
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 maximum balance in the account shall equal the Peaking Supply assigned to the Supplier pursuant to these Terms and Conditions.

DISTRIBUTION AND DEFAULT SERVICE 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 post the Peaking Service Rule Curve on its Website as identified in Section 23.0 of these Terms and Conditions
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.
Pre-Determined Allocation	Instructions from the Supplier to the Company for the allocation of discrepancies in confirmed nominations among the Supplier's Aggregation Pools and/or Customers as set forth in the Supplier's Service Agreement.
Reference Period	A period of at least twelve (12) months for which a Customer's Gas Usage information is typically available to the Company.

DISTRIBUTION AND DEFAULT SERVICE
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Supplier	Any entity licensed by the MDTE 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 (TCQ)	The total amount of Capacity assignable to a Supplier on behalf of a Customer.
Underground Storage	Contracts for capacity in off-system storage Capacity facilities used to accumulate and maintain gas inventories for redelivery to the Company's city gates.
Underground Storage Withdrawal Capacity	Capacity for the withdrawal of gas inventories 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.

DISTRIBUTION AND DEFAULT SERVICE TERMS AND CONDITIONS

13.0 CAPACITY ASSIGNMENT

13.1 Applicability

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

13.2 Identification of Capacity for Assignment

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

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

DISTRIBUTION AND DEFAULT SERVICE TERMS AND CONDITIONS

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

13.3 Determination of Pro-Rata Shares of Capacity

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

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

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

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

DISTRIBUTION AND DEFAULT SERVICE
TERMS AND CONDITIONS

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

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

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

DISTRIBUTION AND DEFAULT SERVICE TERMS AND CONDITIONS

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

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

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

13.4 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, subject to the provisions of Section 13.4.2, be equal to the cumulative sum of the pro-rata shares of Pipeline Capacity, Underground Storage Withdrawal Capacity and Peaking Capacity for all Customers enrolled in said Aggregation Pool as of five (5) Business Days prior to the Assignment Date.

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

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

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

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

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

13.5 Release of Contracts

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

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

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

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

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

13.6 Annual Reassignment of Capacity

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

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

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

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13.7 Recall of Capacity

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

13.8 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.

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

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

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

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

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13.9 Company-Managed Supplies

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

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

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

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

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

13.10 Open-Season Capacity Assignments

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

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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 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.

13.12 Capacity Exempt Customer Reliability Charge

13.12.1 The Company requires access to firm upstream pipeline, storage and peaking capacity as well as on-system peak-shaving resources to maintain the reliability of its distribution system operations. The Capacity Exempt Customer Reliability Charge (CECRC) allows the Company to recover the costs of such resources required in proportion to the level of Capacity Exempt Customer loads on its system.

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13.12.2 Each year, the Company shall calculate a CECRC rate per therm applicable to all Capacity Exempt Customer throughput for the annual period beginning November 1. The CECRC rate per therm and the associated derivation shall be set forth in Appendix C to these Terms and Conditions.

13.12.3 The CECRC rate per therm shall be calculated as follows:

(1) Allowable CECRC costs shall equal the sum of the following:

(a) The product of the total Capacity Exempt Customer peak day requirements, determined prior to November 1, the system average annual unit capacity cost, and a factor of 30% (thirty percent).

(b) A capacity release and off-system sales revenue credit equal to the total projected annual capacity release and off-system sales margin revenues for the annual period beginning November 1 multiplied by the ratio of the total Capacity Exempt Customer peak day requirements to the total system peak day requirements.

(c) Any difference, positive or negative, between the costs of the CECRC as established for the previous annual period November 1 through October 31 and the actual collections from the application of the CECRC rate to Capacity Exempt Customer throughput for the corresponding period.

13.12.4 The total revenues recovered pursuant to the CECRC shall be credited to the Company's CGA costs in accordance with M.D.T.E. No. 36.

13.13 Monitoring Capacity Exempt Customer Overtakes

13.13.1 Overtakes associated with Capacity Exempt Customer loads threaten the reliability of Bay State's distribution system. Therefore, the Company shall monitor Supplier overtakes associated with Capacity Exempt Customer loads on Critical Days.

13.13.2 All Capacity Exempt Customers served by a Supplier that experiences an overtake on a Critical Day that exceeds thirty percent (30%) of the aggregate Gas Usage of Capacity Exempt Customers within its Aggregation Pool shall lose their status as exempt from the mandatory capacity assignment provisions of these Terms and Conditions. In order to determine whether a Supplier has exceeded the allowed 30% overtake for Capacity Exempt Customer loads, the Company shall perform the following calculations

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applicable to Daily-Metered and Non-Daily Metered Aggregation Pools for each day that the Company declares a Critical Day and provides notice thereof to Suppliers pursuant to Section 19.0 of these Terms and Conditions.

(1) For Daily Metered Pools, the Company shall determine the receipts applicable to Capacity Exempt Customer loads by subtracting the total metered Gas Usage for all non-Capacity Exempt Customers in the Aggregation Pool divided by a factor of one hundred and two percent (102%) from the total deliveries for the Aggregation Pool. The total Gas Usage for all Capacity Exempt Customers in the Aggregation Pool shall be subtracted from the receipts for Capacity Exempt Customers calculated pursuant to this provision to determine the overtake applicable to Capacity Exempt Customers, if any. The percentage overtake shall be determined by dividing the Capacity Exempt Customer overtake into the total Gas Usage for all Capacity Exempt Customers in the Aggregation Pool.

(2) For Non-Daily Metered Pools, the Company shall calculate the percentage overtake for the Aggregation Pool by subtracting the ATV from the actual receipts from the Supplier. The percentage overtake for the Aggregation Pool shall be determined by dividing the overtake for the Aggregation Pool by the ATV. The percentage overtake for Capacity Exempt Customers in the Non-Daily Metered Aggregation Pool shall equal the percentage overtake for the total Aggregation Pool.

(3) The calculation of Capacity Exempt Customer overtakes shall not take into consideration trading of daily imbalances by Suppliers as permitted under Section 24.7.

13.13.3 All Capacity Exempt Customers of a Supplier whose overtake on a Critical Day exceeds thirty percent as calculated pursuant to Section 13.13.2 shall forego their capacity assignment exemption. Further, each Supplier serving said Capacity Exempt Customers shall be assigned capacity pursuant to these Terms and Conditions on the next allowable assignment date.

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APPENDIX C

Capacity Exempt Customer Reliability Charge

Row	Description	Amount	Calculation
(1)	Capacity Exempt Customer Peak Day	XX Dth	
(2)	Average Annual Unit Capacity Cost	$__ per Dth	
(3)	Factor	30%	
(4)	Reliability Costs		(1) x (2) x (3)
(5)	Capacity Release / OSS Margin Revenues	$___	
(6)	Total System Design Day	XX Dth	
(7)	Capacity Release / OSS Credit		(5) x ((1)/(6)
(8)	Prior Period Under / (Over) Recovery	$___	
	Total CECRC Allowable Costs for Period	$____	(4) + (7) + (8)
(10)	Capacity Exempt Customer Throughput	Dth	
(11)	CECRC Charge per therm	$____	(9) / (10)

COST OF GAS ADJUSTMENT CLAUSE

Section

1.0 Purpose

The purpose of this clause is to establish procedures that allow Bay State Gas Company ("Bay State" or the "Company"), subject to the jurisdiction of the Department of Telecommunications and Energy ("Department") to adjust, on a semiannual basis, its rates for firm gas sales service in order to recover the costs of gas supplies, along with any taxes applicable to those supplies, pipeline and storage capacity, production capacity and storage, bad debt expense associated with purchase gas costs, and the costs of purchased gas working capital, to reflect the seasonal variation in the cost of gas, and to credit all supplier refunds and the margins above the Annual Threshold associated with capacity credits from non-core sales and transportation, interruptible sales and transportation and capacity release sales, as well as revenues from the billing of the Capacity Exempt Customer Reliability Charge, to firm ratepayers.

2.0 Applicability

This Cost of Gas Adjustment Clause ("CGAC") shall be applicable to Bay State and all firm gas sales made by Bay State, unless otherwise designated. The application to the clause may, for good cause shown, be modified by the Department. See Section 13.0, "Other Rules."

COST OF GAS ADJUSTMENT CLAUSE

3.0 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, other gas supply expense incurred to procure and transport supplies and bad debt percent (from the last general rate case) applied to allowable CGAC costs for the forecast period, 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 filings outlined in Section 12.0.

4.0 Effective Date of Gas Adjustment Factor

The date on which the seasonal Gas Adjustment Factors ("GAF") become effective shall be the first day of the first month of each season as designated by the Company. Unless otherwise notified by the Department, the Company shall submit GAF filings as outlined in Section 12.0 of this clause at least 45 days before they are to take effect.

5.0 Definitions

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

(1) **Annual Threshhold** - A threshold level of margins, established annually and separately for Capacity Release, Interruptible Sales and Off-System Sales, based on the twelve months ended April 30 each year, the level above which the Company retains 25% of such margins.

(2) **Bad Debt Expense** - is the uncollectable expense attributed to the Company's gas costs plus allowable working capital derived from the gas cost portion of bad debt.

(3) **Base Load Requirements** - The annual quantity of gas supply needed to satisfy the lowest level of firm demand based on the average July and August loads.
Capacity Exempt Customer Reliability Charge ("CECRC") Revenues – The revenues from billing the CECRC to capacity exempt firm transportation customers for the cost of capacity resources needed for system reliability and based on 30% of the capacity exempt design day requirements.

(~~4~~5) **Capacity Release Revenues** - The economic benefit derived from the sale of upstream capacity.

(~~5~~6) **Carrying Charges** - Interest expense calculated on the average monthly balance using the consensus prime rate as reported in the *Wall Street Journal*.

(~~6~~7) **Economic Benefit** - The difference between the revenues received and the marginal cost determined to serve non-core customers.

COST OF GAS ADJUSTMENT CLAUSE

(~~7~~8) **Interruptible Sales Margins** - The economic benefit derived from the interruptible sale of gas downstream of the Company's distribution system.

(~~8~~9) **Inventory Finance Charges** - As incurred or billed each month for the carrying costs on the value of the balance of inventory gas for the respective month. The total charges shall represent an accumulation of the projected monthly charges as calculated using the monthly average of financed inventory at the existing (or anticipated) financing rate of the Company or through a trust or other financing vehicle.

(~~9~~10) **Local Production Capacity and Storage Costs** - Include the ancillary supply costs of providing local manufactured gas, gas dispatching, gas acquisition, and miscellaneous A&G costs as determined in the Company's most recent rate proceeding.

(11~~0~~) **SMBA** – Simplified Market Based Allocation Method - Used in determining the allocation of gas costs among High and Low Load Factor classes.

(12~~1~~) **Non-Core Commodity Costs** - The commodity cost of gas assigned to non-core sales to which the GAF is not applied. Non-core sales include sales made under interruptible contracts, non-core contracts and off-system sales.

(13~~2~~) **Non-Core Sales Margins** – The economic benefit derived from non-core transactions to which the GAF is not applied, including interruptible sales and other non-core sales generated from the use of the Company's Gas Supply resource portfolio.

(14~~3~~) **Off-System Sales Margin** - The economic benefit derived from the non-firm sales of natural gas supplies upstream of Company's distribution system.

(15~~4~~) **Number of Days Lag** - The number of days lag to calculate the purchased gas working capital requirement as approved by the Department.

(16~~5~~) **Off-Peak Commodity** – Unless otherwise approved by the Department, the gas supplies assigned by the Company to serve firm load in the off-peak season.

(17~~6~~) **Off-Peak Demand** - Unless otherwise approved by the Department, the gas supply demand and transmission capacity assigned by the Company to serve firm load in the off-peak season.

(18~~7~~) **Off-Peak Period** - May through October.

(19~~8~~) **Peak Commodity** - Unless otherwise approved by the Department, the gas supplies assigned by the Company to serve firm load in the peak season.

(20~~19~~) **Peak Demand** - Unless otherwise approved by the Department, gas supply demand, peaking demands, storage and transmission capacity assigned by the Company to service firm load in the peak season.

(21~~0~~) **Peak Period** - November through April.

(22~~1~~) **PR Allocator** - The percentage allocated for the portion of annual capacity charges assigned to the seasons calculated in each CGA filing.

(23~~2~~) **Pretax Weighted Cost of Capital** - The result of the calculation of the weighted cost of capital minus the weighted cost of debt, divided by one, minus the currently effective combined tax rate, plus the weighted cost of debt.

(24~~3~~) **Purchased Gas Working Capital** - The allowable working capital derived from peak and off-peak, demand and commodity related costs.

COST OF GAS ADJUSTMENT CLAUSE

(24~~5~~) **Tax Rate** is the combined State and Federal income tax rate.

(26~~5~~) **Weighted Cost of Capital** is the weighted cost of capital as set in the Company's most recent base rate case.

(27~~6~~) **Weighted Cost of Debt** is the weighted cost of debt as set in the Company's most recent base rate case.

6.0 Gas Adjustment Factor (GAF) Formula

The Gas Adjustment Factor ("GAF") Formula shall be computed on a semiannual basis using forecasts of seasonal gas costs, carrying charges, sendout volumes, and sales volumes. Forecasts may be based on either historical data or Company projections, but must be weather-normalized. Any projections must be documented in full with each filing.

A separate seasonal GAF will be computed for the combined Low Load Factor classes namely Rates R-3, R-4, G-40, G-41, G-42 and G-43; and for the combined High Load Factor classes namely Rates R-1, R-2, OL, G-50, G-51, G-52 and G-53. The calculation of each seasonal GAF utilizes information periodically established by the DTE. The table below lists the following approved cost factors as approved in D.T.E. 05-27:

Local Production & Storage Cost	$7,430,587
LNG/LPG Production Cost included above	$5,045,484
Bad Debt Expense Percentage	2.15%

Peak GAF Formula

The Peak GAF shall be comprised of a peak demand factor (DFp), a peak commodity factor (CFp), a peak production and storage demand factor (PSp), gas suppliers' refund factors (R1 and R2) defined in Section 8.00 and a bad debt factor (BDF) defined in Section 15.00, for the Company's High and Low Load Factor classes and calculated at the beginning of the peak season according to the following formula:

$$GAFp^x = DFp^x + PSp^x + CFp^x + BDF - R1 - R2$$

Peak Demand Factor (DFp) Formula

$$DFp^x = \frac{Dp^x - NCSMp^x - CECRCR}{P : Sales^x} + RFpd + WCFpd$$

COST OF GAS ADJUSTMENT CLAUSE

and:

$Dp^x = BASEDp^x + REMAINDp^x + PSp^x$

and:

$NCSMp^x = CRR^x + ISM^x + NTSM^x$

and:

$RFpd = Rpd/P{:}Sales$

and:

$$WCFpd = \frac{\dfrac{[(WCApd \times CC) - (WCApd \times CD)]}{(1 - TR)} + (WCApd \times CD) + WCRpd}{P : Sales}$$

and:

$WCApd = Dp \times (DL/365)$

Where:

BASEDp	Peak period base use demand charges assigned on the basis of base use entitlements to low cost pipeline supplies using the average of July and August's daily loads.
CC	Weighted cost of capital as defined in Section 500.
CD	Weighted cost of debt as defined in Section 5.00.
CECRCR	Revenues from billing the Capacity Exempt Customer Reliability Charge.
CRR	The returnable Capacity Release Revenues allocated to the peak period. See Section 7.00.
DL	Number of days lag from the purchase of gas from suppliers to the payment by customers.
Dp	Demand Charges allocated to the peak period as defined in Section 5.00.
$NCSMp^X$	The sum of the returnable Interruptible Non-Core Sales Margins, the returnable Capacity Release Revenues and the Off-System margins.
ISM	The returnable Interruptible Sales Margins allocated to the peak period. See Section 7.00.
NTSM	The returnable Off-System Sales Margins allocated to the peak period. See Section 7.00.
P:Sales	Forecasted sales volumes associated with the peak period.
REMAINDp	Peak period remaining use demand charges assigned to classes on the basis of their load's contribution to the design day load less their base use entitlements to pipeline supplies.

COST OF GAS ADJUSTMENT CLAUSE

	This remaining capacity cost is allocated to seasons using the Proportional Responsibility (PR) allocator.
RFpd	Peak demand charge reconciliation adjustment factor per billed peak sales volume associated with demand charges related to the peak period.
Rpd	Reconciliation Costs - Peak demand deferred gas costs, Account 175.21 balance, inclusive of the associated Account 175.21 interest, as outlined in Section 9.00.
TR	Combined Tax Rate as defined in Section 5.00
WCApd	Demand charges allowable for working capital application as defined in Section 10.00.
WCFpd	Working Capital allowable factor per billed peak sales volume associated with demand charges allocated to the peak period as defined in Section 10.00.
WCRpd	Working Capital reconciliation adjustment associated with peak demand charges - Account 176.24 balance as outlined in Section 10.00.
x	Designates Load Factor Specific allocation of costs, based on Simplified Market Based Allocation factors as determined in the Company's most recent rate proceeding.
PSpx	Portion of test year Local Production Capacity and Storage Costs, as defined in Section 5.00, allocated to peak period firm sales through the CGAC as determined in the Company's most recent rate proceeding.

Peak Commodity Factor (CFp) Formula

$$CFp^x = \left[\frac{Cp^x - NCCCp^x + FC^x}{P : Sales^x} \right] + RFpc + WCFpc$$

and:

$$Cp^x = BASECp^x + REMAINCpx$$

and:

$$RFpc = Rpc / P{:}Sales$$

and:

$$WCFpc = \frac{\left[\frac{(WCApc \times CC) - (WCApc \times CD)}{(1 - TR)} \right] + (WCApc \times CD) + WCRpc}{P{:}\ Sales}$$

and:

$$WCApc = Cp \times (DL/365)$$

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Where:

BASECp	Peak period base use commodity charges assigned on the basis of base use entitlements to low cost pipeline supplies using the average of July and August daily loads.
CC	Weighted costs of capital as defined in Section 5.00
CD	Weighted costs of debt as defined in Section 5.00.
Cp	Commodity Charges allocated to the peak period as defined in Section 5.00.
DL	Number of days lag from the purchase of gas from suppliers to the payment by customers.
FC	Inventory finance charges as defined in Section 5.00.
NCCCp	Non-Core Commodity Costs allocated to the peak period as defined in Section 5.00.
P:Sales	Forecasted sales volumes associated with the peak period.
REMAINCp	Peak period remaining use commodity charges computed as dispatched commodity costs less base use commodity costs.
RFpc	Peak commodity charge reconciliation adjustment factor per billed peak sales volume associated with commodity charges related to the peak period.
Rpc	Reconciliation Adjustment Costs - Account 175.23 balance, inclusive of the associated Account 175.23 interest, as outlined in Section 9.00.
R	Combined Tax rate as defined in Section 5.00.
WCApc	Commodity charges allowable for working capital application as defined in Section 10.00.
WCFpc	Working Capital allowable factor per peak sales volume associated with commodity charges allocated to the peak period as defined in Section 10.00.
WCRpc	Working Capital reconciliation adjustment associated with peak commodity charges Account 175.24 balance as outlined in Section 10.00.
x	Designates Load Factor class specific allocation of costs, based on Simplified Market Based Allocation factors, as determined in the Company's most recent rate proceeding.

Off-Peak GAF Formula

The Off-Peak GAF shall be comprised of an off-peak demand factor (Dfop) an off-peak production and storage demand factor (PSop), an off-peak commodity factor (Cfop), gas suppliers' refund factors (R1 and R2) defined in Section 8.00 and a bad debt factor (BDF), defined in Section 15.00 for the Company's High and Low Load Factor classes, and calculated at the beginning of the off-peak season according to the following formula.

$$GAFop^{X} = DFop^{X} + CFop^{X} + PSop^{x} + BDF - R1 - R2$$

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Off-Peak Demand Factor (DFop) Formula

$$DFop^{x} = \frac{Dop^{x}}{OP{:}Sales^{x}} + RFopd + WCFopd$$

and:

$$Dop^{X} = Sum{:}BLDop^{X} + (Sum{:}BLDXop^{X} \times (1 - PR))$$

and:

$$RFopd = Ropd / OP{:}Sales$$

and:

$$WCFopd = \frac{\dfrac{[(WCAopd \times CC) - (WCAopd \times CD)]}{(1 - TR)} + (WCAopd \times CD) + WCRopd}{(OP{:}Sales)}$$

and:

$$WCAopd = Dop\ (DL/365)$$

Where:

BLDop	Demand charges billed to the Company during the off peak period for the portion of base demand associated with serving base load requirements as defined in Section 5.00.
BLDXop	Base demand costs in excess of demand costs associated with base load level billed to the Company during the off-peak period.
CC	Weighted cost of capital as defined in Section 5.00.
CD	Weighted cost of debt as defined in Section 5.00
DL	Number of days lag from the purchase of gas from suppliers to the payment by customers.
Dop	Demand charges allocated to the off-peak period as defined in Section 5.00.
OP:Sales	Forecasted sales volumes associated with the off-peak period.
PR	Proportional Responsibility Allocator - A percentage representing a portion of capacity/product charges incurred in the off-peak season and assigned to the peak period calculated in each CGA filing as defined in Section 5.0.
RFopd	Off-peak demand charge reconciliation adjustment factor per billed off peak throughput

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	volume associated with demand charges related to the off peak period.
Ropd	Reconciliation Costs - Account 175.11 balance, inclusive of the associated Account 175.11 interest, as outlined in Section 9.00.
SMBA	Simplified Market Based Allocator – Load Factor specific allocator as defined in Section 5.00
TR	Combined Tax rate as defined in Section 5.0
WCAopd	Demand charges allowable for working capital application as defined in Section 6.1.
WCFopd	Working Capital factor allowable per billed off-peak sales associated with demand charges allocated to the off-peak period as defined in Section 10.0
WCRopd	Working Capital reconciliation adjustment associated with off-peak demand charges balance account 175.14 balance as outlined in Section 10.0.
x	Designates Load Factor specific allocation of costs based on Simplified Market Based Allocation factors, as determined in the Company's most recent rate proceeding.
PS_{op}^{x}	Portion of test year Local Production Capacity and Storage Costs, as defined in Section 5.00, allocated to off-peak period firm sales through the CGAC as determined in the Company's most recent rate proceeding.

Off-Peak Commodity Factor (CFop) Formula

$$CFop^{x} = \frac{Cop^{x} - NCCCop^{x}}{OP : Sales^{x}} + RFopc + WCFopc$$

and:

$$Cop^{X} = Sum{:}OPC^{X} - BOao^{X} - INJop^{X} - LIQop^{X}$$

and:

$$BOao^{X} = [(BOop - (BOvolop \times (TPop/TPvolop)))\ SMBA^{X}]$$

and:

$$RFopc = Ropc/OP{:}Sales$$

and:

$$WCFopc = \frac{\frac{[(WCAopc \times CC)-(WCAopc \times CD)]}{(1 - TR)} + (WCAopc \times CD) + WCRopc}{OP : Sales}$$

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and:

WCAopc = Cop (DL/365)

Where:

BOao	LNG Boil-off allocation as defined in Section 9.00.
BOop	Cost of LNG Boil-off during the off-peak period.
BOvolop	LNG Boil-off volumes purchased in the off-peak period.
CC	Weighted cost of capital as defined in Section 5.00.
CD	Weighted cost of debt as defined in Section 5.00.
Cop	Commodity Charges billed to the off-peak period as defined in Section 5.00
DL	Number of days lag from the purchase of gas from suppliers to the payment by customers. See Section 10.00.
INJop	Injections into underground storage during the off-peak period.
LIQop	Liquefactions into storage during the off-peak period.
NCCCop	Non-core commodity costs allocated to the off-peak period as defined in Section 6.05.
OP:Sales	Forecasted sales volumes associated with the off-peak period.
OPC	Commodity charges associated with gas supply sent out in the off-peak season as defined in Section 5.00.
RFopc	Off peak commodity charge reconciliation adjustment factor per billed off peak sales volume associated with commodity charges related to the off-peak period.
Ropc	Reconciliation Adjustment Cost - Account 175.13 balance, inclusive of the associated Account 175.13 interest, as outlined in Section 9.00.
TPop	Total pipeline commodity purchase charges for the off-peak period.
TPvolop	Total pipeline purchase volumes for the off-peak period.
TR	Combined Tax rate as defined in Section 5.00.
WCAopc	Commodity charges allowable for working capital application as defined in Section 10.00.
WCFopc	Working Capital allowable per off-peak sales volume associated with commodity charges allocated to the off-peak period as defined in Section 10.00.
WCRopc	Working Capital reconciliation adjustment associated with off-peak commodity charges - Account 176.14 balance, as outlined in Section 10.00.
x	Designates Load Factor specific allocation of costs, based on Simplified Market Based Allocation factors.

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7.0 Interruptible Sales, Off-System Sales and Capacity Release Revenues

A threshold level of margins will be established annually and separately for Interruptible Sales, Off-System Sales and Capacity Release Revenues. Any margins earned in excess of the predetermined level shall be divided between the Company and its firm sales customers under a 25/75 sharing arrangement. The threshold level of margins shall be adjusted to reflect additions or losses from Customers who switch from FT, FS or Interruptible Transportation ("IT") to IS and conversely, from IS to FT, FS or IT. The Company shall adjust the threshold level annually to reflect Interruptible Sales, Off-System sales, and capacity release revenues for the twelve-month period ending April 30 of each year.

Margins from Interruptible Sales, Off-System Sales and Capacity Release will be reflected as separate credits in the peak season GAF and shall be calculated as the sum of the following:

(1) 100% of the margins earned up to the predetermined threshold level.
(2) 75% of the margins earned in excess of the predetermined threshold level.

8.0 Gas Suppliers' Refunds - Accounts 265.85 and 265.86

Refunds from upstream capacity suppliers and suppliers of gas are credited to Account 265.85, "Refund-November" if received during the months of March through August, and to Account 265.86 "Refund-May", if received during the months of September through February.

A refund program shall be initiated with each semiannual GAF filing and shall remain in effect for a period of one year. The balance in Account 265.85 shall be placed into a refund program with each November filing. The balance in Account 265.86 shall be placed into a refund program with each May filing. The total dollars to be placed into a given refund program shall be net of over/under-returns from expired programs plus refunds received from suppliers since the previous program was initiated. The Company shall track and report on all Account 265.85 and Account 265.86 activities. If during any twelve-month period commencing with the billing month of November for Account 265.85 and May for Account 265.86, the projected supplier refund factor is less than one-hundredth of a cent per therm ($0.0001), the respective supplier refund account balance shall be transferred into Account 175.26 or Account 175.16 for the November and May filings respectively.

Gas Supplier's Refund Factors

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R1 The per unit supplier refund associated with the Refund – May program. The following formula shall be used to calculate the R1 factor.

$$R1 = \frac{R1\$ + I}{A{:}Sales}$$

Where:

R1$ Ending balance in Account 265.86 "Refund – May"
I Total forecasted interest calculated on the R1$ balance computed at the consensus prime rate as reported in the *Wall Street Journal* based on a 365 day year.
A:Sales Forecasted annual firm sales volumes.

R2 The per unit supplier refund associated with the Refund – November program. The following formula shall be used to calculate the R2 factor.

$$R2 = \frac{R2\$ + I}{A{:}Sales}$$

Where:

R2$ Ending balance in Account 265.85 "Refund – November"
I Total forecasted interest calculated on the R2$ balance computed at the Federal Reserve Prime Rate based on a 365 day year.
A:Sales Forecasted annual firm sales volumes.

9.0 Reconciliation Adjustments – Other than Working Capital

(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.
ii. Charges associated with transmission capacity procured by the Company to serve base load requirements in the peak season.
iii. Charges associated with upstream storage and transmission capacity procured by the Company to serve firm load in excess of base load

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requirements in the peak period, plus a reallocation of a portion of such charges incurred in the off-peak season to serve firm load.

iv. Charges associated with peaking, production and storage capacity to serve firm load in the peak season as determined in the test year of the Company's most recent rate proceeding and allocated to firm sales storage service.

v. Credits associated with Non-Core Sales Margins or economic benefits from capacity release, off-system sales for resale and interruptible sales margins allocated to the firm sales service.

vi. Credits associated with daily imbalance charges billed transportation customers in the peak period.

vii. Credits associated with Capacity Exempt Customer Reliability Charges billed to Capacity Exempt Customers in the peak period in accordance with M.D.T.E. No. 35, Section 13.12.

viii. Peak demand Carrying Charges as defined in Section 5.00.

(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.

ii. Credit non-core commodity costs assigned to non-core customers to which the CGAC does not apply, as defined in Section 6.06 (NCCCp).

iii. Inventory finance charges (FC).

iv. Peak commodity Carrying Charges as defined in Section 5.00.

(c) Capacity Costs Allowable Per Off-Peak Demand Formula shall be:

i. Charges associated with transmission capacity and product demand procured by the Company to serve base load requirements in the off peak season.

ii. Charges associated with transmission capacity and product demand procured by the Company to serve firm load in excess of base load requirements in the off-peak period

iii. Credits associated with daily imbalance charges billed transportation customers in the off peak period.

iv. Off-peak demand Carrying Charges as defined in Section 5.00.

v. Other A & G and Acct. 851 charges associated with peaking production and storage capacity to serve firm load in the off-peak season as determined in the test year of the Company's most recent rate proceeding and allocated to firm sales storage service

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(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 purchases in the off-peak period, less the cost of injections and liquefactions into storage.

ii. Credits associated with Non-core commodity costs from non-core sales to which the GAF is not applied, as defined in Section 5.00.

iii. Off-peak commodity Carrying Charges as defined in Section 5.00.

(2) **Calculation of the Reconciliation Adjustments**

Account 175 contains the accumulated difference between gas cost revenues and the actual monthly gas costs incurred by the Company. The Company shall separate Account 175 into Peak Demand (Account 175.21), Peak Production and Storage Demand (175.22), Peak Commodity (Account 175.23), Off-Peak Demand (Account 175.11), Off-Peak Production and Storage Demand (175.12) and Off-Peak Commodity (Account 175.13). Account 175.21 shall contain the accumulated difference between revenues toward capacity costs calculated by multiplying the Peak Demand Factor for the High and Low Load Factor classes, (DFp^X) times monthly firm sales volumes for High and Low Load Factor classes, and the total capacity costs allowable per the peak demand formula. Account 175.22 shall contain the accumulated difference between revenues toward gas costs as calculated by multiplying the Peak Commodity Factor for the High and Low Load Factor classes, (CFp^X) times monthly firm sales volumes for High and Low Load Factor classes, and the total commodity costs allowable per the peak commodity formula. Account 175.22 shall contain the accumulated difference between revenues as calculated by multiplying the Peak Production and Storage Demand Factor for the High and Low Load Factor class, (PS_p^x) times monthly firm sales volumes forthe High and Low Load Factor classes, and the total production and storage costs allowable per the peak production and storage demand formula. Account 175.11 shall contain the accumulated difference between revenues toward capacity costs calculated by multiplying the Off-Peak Demand Factor for the High and Low Load Factor classes, ($DFop^X$) times monthly firm sales volumes for the High and Low Load Factor classes, and the total capacity costs allowable per the off-peak demand formula. Account 175.13 shall contain the accumulated difference between revenues toward gas costs as calculated by multiplying the Off-Peak Commodity Factor for the High and Low Load Factor

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classes, ($CFop^X$) times monthly firm sales volumes for the High and Low Load Factor classes, and the total commodity costs allowable per the off-peak commodity formula. Account 175.12 shall contain the accumulated difference between revenues as calculated by multiplying the Off-Peak Production and Storage Demand Factor for the High and Low Load Factor classes, (PS_{op}^x) times monthly firm sales volumes for the High and Low Load Factor classes, and the total production and storage costs allowable per the off-peak production and storage demand formula.

Carrying Charges as defined in Section 5.00 shall be added to each end-of-the-month balance. The peak demand reconciliation adjustment factor (RFpd) shall be determined for use in the peak GAF calculation by dividing the peak demand account (175.21) balance as of the peak reconciliation date, by the forecasted sales volume associated with the peak period. The peak production & storage demand reconciliation adjustment factor (RFppsd) shall be determined for use in the peak GAF calculation by dividing the peak production and storage demand account (175.22) balance as of the peak reconciliation date, by the forecasted sales volume associated with the peak period. The peak commodity reconciliation adjustment factor (RFpc) shall be determined for use in the peak GAF calculation by dividing the peak commodity account (175.23) balance as of the peak reconciliation date, by the forecasted sales volume associated with the peak period. The off-peak demand reconciliation adjustment factor (RFopd) shall be determined for use in the off peak GAF calculation by dividing the off-peak demand account (175.11) balance as of the off-peak reconciliation date, by the forecasted sales volume associated with the off-peak period. The off-peak production and storage demand reconciliation adjustment factor (RFoppsd) shall be determined for use in the off-peak GAF calculation by dividing the off-peak production and storage demand account (175.12) balance as of the off-peak reconciliation date, by the forecasted sales volume associated with the off-peak period. The off-peak commodity reconciliation adjustment factor (RFopc) shall be determined for use in the off-peak GAF calculation by dividing the off-peak commodity account (175.13) balance as of the off-peak reconciliation date, by the forecasted sales volume associated with the off-peak period.

The peak period reconciliation will be filed thirty (30) days prior to the peak period GAF filing, which is seventy-five (75) days prior to the effective date.

The off-peak period reconciliation shall be filed thirty (30) days prior to the off-peak period GAF filing, which is seventy-five (75) days prior to the effective date.

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10.0 Working Capital Reconciliation Adjustments

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

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

i. Charges associated with upstream storage, transmission capacity, and product demand procured by the Company to serve firm load in the peak season.
ii. Charges associated with transmission capacity procured by the Company to serve base load requirements in the peak season.
iii. Charges associated with upstream storage and transmission capacity procured by the Company to serve firm load in excess of base load requirements in the peak period, plus a reallocation of a portion of such charges incurred in the off-peak season to serve firm load.
iv. Carrying Charges

(b) Working Capital 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 costs 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 liquefactions into storage.
ii. Non-Core Commodity Costs associated with non-core sales to which the GAF is not applied.
iii. Carrying charges.

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

i. Charges associated with transmission capacity procured by the Company to serve base load requirements in the off peak season.
ii. Charges associated with upstream storage and transmission capacity procured by the Company to serve firm load in excess of base load requirements in the off-peak period.
iii. Carrying charges.

(d) Working Capital 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

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average cost of LNG boiloff in the off-peak period times the LNG boiloff volumes purchases in the off-peak period, less the cost of injections and liquefactions into storage.

ii. Non-core commodity costs associated with non-core sales to which the GAF is not applied, as defined in section 6.05.

iii. Carrying charges.

(2) The peak and off-peak, demand, and commodity 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.

(3) The peak and off-peak, demand, and commodity working capital allowances shall each be calculated by applying the Company's weighted cost of capital to each working 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 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) Calculation of the Reconciliation Adjustments

Accounts 175.14, 175.13, 175.24, and 175.23 contain the accumulated difference between working capital allowance revenues and the actual monthly working capital allowance costs as calculated from actual monthly costs for the Company plus Carrying Charges as defined in Section 5.00.

The components of the Company's purchased gas days lag shall be recalculated each season based upon actual CGAC seasonal data. This recalculated days lag will be used in the calculation of the working capital allowance revenues. Each Account 175 shall contain the accumulated difference between revenues toward the working capital allowance and the working capital allowance.

The peak demand working capital reconciliation adjustment shall be determined for use in the peak demand factor calculations incorporating the peak demand working capital account 175.14 balance as of the peak reconciliation date designated by the Company. A peak commodity working capital reconciliation adjustment shall be determined for use in the peak commodity factor calculations incorporating the peak commodity working capital account 175.13 balance as of the peak reconciliation date designated by the Company. An off-peak working capital reconciliation adjustment (WCRopd) shall be determined for use in the off-peak demand factor calculations incorporating the off-peak

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demand working capital account (175.24) balance as of the off-peak reconciliation date designated by the Company. An off-peak commodity working capital reconciliation adjustment (WCRopc) shall be determined for use in the off-peak commodity working capital account (175.23) balance as of the off-peak reconciliation date designated by the Company.

11.0 Application of GAF to Bills

The Company will employ the GAFs as follows: The peak season rates to each Load Factor class shall be calculated by adding the respective peak demand factor and the peak commodity factor. The off-peak season rates to each Load Factor class shall be calculated by adding the respective off-peak demand factor and the off-peak commodity factor. The GAFs ($/therm) for each Load Factor class for each season shall be calculated to the nearest one-hundredth of a cent per therm ($0.0001) and will be applied to each customer's monthly sales volume within the corresponding Load Factor class.

12.0 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 Company's standardized forms approved by the Department. Required filings include 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 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.

13.0 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 10 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 GAF.
(4) The operation of the cost of gas adjustment clause is subject to all powers of suspension

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and investigation vested in the Department by G.L. c.164.

14.0 Customer Notification

The Company will design a notice, which explains in simple terms to customers the GAF, the nature of any change in the GAF and the manner in which the GAF is applied to the bill. 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.

15.0 Bad Debt Allowance

15.01 Purpose

The purpose of this provision is to establish a procedure that, subject to the jurisdiction of the Department, allows Bay State to adjust, on a semi-annual basis, its rates for the recovery of Bad Debt Expense

15.02 Bad Debt (BDF) Formula

The Bad Debt (BDF) Formula shall be computed on an annual bas is using forecasts of bad debt expense associated with gas costs, gas costs, carrying charges, sales volumes, and a working capital allowance. Forecasts may be based on either historical data or Company projections, but must be weather-normalized. Any projections must be documented in full with each filing. The forecast of bad debt expense associated with gas costs shall be based on the Company's projected gas costs in the respective seasonal GAF filings and the percent of net write-offs to total firm revenues as determined in the Company's last rate proceeding.

The calculation at the beginning of the off-peak season shall be on a projected annual basis. The calculation at the beginning of the peak season will update the remaining months of the projected annual period with actual bad debt expenses and collections for the available months and projections for the remaining months of the annual period. The following formula shall be used to calculate the Bad Debt factor.

$$BDF = \frac{BD + RAbd + WCbd}{A:Sales}$$

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and:

$$WCbd = \frac{(WCAbd * CC) - (WCAbd * CD)}{(1 - TR)} + (WCAbd * CD)$$

and:

WCAbd = BD * (DL/365)

Where:

A:Sales	Forecast annual sales volumes.
BD	Forecast Bad Debt Expense as defined in Section 5.00; derived by multiplying the forecast annual gas costs by the percent of annual net write-offs to annual firm revenues as determined in D.T.E. 05-27.
CC	Weighted cost of capital as defined in Section 5.00.
CD	Weighted cost of debt as defined in Section 5.00.
DL	Number of days lag from the purchase of gas from suppliers to the payment by customers.
RAbd	Bad Debt Expense reconciliation adjustment - Account 175.31 balance.
TR	Combined Tax rate as defined in Section 5.00.
WCAbd	Bad Debt allowable for working capital application defined as the costs associated with the gas cost portion of bad debt incurred by the Company to serve firm load.
WCbd	Working Capital Allowance associated with the gas portion of bad debt for the period including the Pretax Weighted Cost of Capital as defined in Section 5.00.

15.03 Bad Debt Reconciliation Adjustment

Account 175.31 shall contain the accumulated difference between the annual revenues toward bad debt, as calculated by multiplying the bad debt factors (BDF) times monthly firm sales volumes, and the annual allowed Bad Debt expenses, allowed working capital on Bad Debt and Carrying Charges as defined in Section 5.00.

An annual bad debt reconciliation adjustment (RAbd - as defined in Section 15.02) shall be determined for use in the bad debt factor calculations incorporating the bad debt working capital account (175.32) balance as of the reconciliation date designated by the Company.

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(a) Costs Allowable per Bad Debt Formula shall be:

i. Un-collectable gas costs incurred by the Company to serve firm sales load, as determined by deriving the portion of actual net write-offs associated with gas cost collections.

ii. Account 175.32 – Bad Debt, Carrying Charges.

iii. Working Capital Gas Costs Allowable per Bad Debt Formula, which shall be charges associated with bad debt incurred by the Company to serve firm sales load and applied to the working capital formula.

NiSource
Corporate Services

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October 5, 2006

VIA E-FILE AND OVERNIGHT COURIER

Mary L. Cottrell, Secretary
Department of Telecommunications and Energy
One South Station
Boston, MA 02110

Re: Bay State Gas Company, D.T.E. 06-36
Compliance Tariff for Proposal for Grandfathered Overtakes

Dear Ms. Cottrell:

On behalf of Bay State Gas Company ("Bay State"), and pursuant to the requirement of the Hearing Officer in this proceeding, be advised that the following materials in this proceeding will be amended due to the data clarification and revised planning standard identified by Bay State on October 2, 2006. All amendments are identified with bold, italicized text.

1. Bay State's Petition for Approval of System Protection Plan for Grandfather Overtakes, one reference on page 2 only;

2. Exhibit JAF-4 (redlined versions of Proposed M.D.T.E. No. 35 and M.D.T.E. No. 36): page 22 of 45 (Section 13, at page 13-13); page 24 of 45 (Appendix C); and page 26 of 45 (page 2). (These amendments would similarly be reflected in the clean versions of the proposed tariffs);

3. Exh. BSG-1, the Testimony and Exhibits of Joseph A. Ferro, Bay State's Manager, Regulatory Policy, 9 pages of minimally amended text, and one line in Amended Exhibit JAF-3 (page 1 of 1);

4. Bay State responses to Department Information Requests 1-2, 1-25, 2-2, 3-7 and 3-8;

5. Bay State responses to Attorney General Information Requests 1-6, 1-7, 1-9, 1-10, 1-15, 1-18, 2-1, 2-2, 2-3, 2-8, 2-10, and 3-7;

6. Bay State responses to Sprague Information Requests 1-2, 1-11, 1-13, and 1-15;

7. Bay State responses to Hess Information Requests 1-15, 1-23, 2-4, 2-6, and 2-8; and,

8. Bay State also expects to supplement Hess 1-16, in order to provide clarification, although the response is correct and complete in its current form.

Bay State notes that only 26 of more than 142 filed information request responses (including supplements) will need to be amended as a result of Bay State's data clarification. Bay State is convinced that the foundation of its proposal continues to be valid and in the interest of the safety, integrity and reliability of its distribution operating system. Bay State expects to file these amendments on October 6, 2006.

Please do not hesitate to contact me at (508) 836-7394 or Robert L. Dewees, Jr., of Nixon Peabody LLP, at (617) 345-1316 with any questions concerning this notice.

Very truly yours,

Patricia M. French

cc: Julie Howley Westwater, Esq., Hearing Officer
Kevin Brannelly, Director, Rates and Revenue Requirements, DTE
George Yiankos, Director, Gas Division, DTE
Jamie Tosches, Esq., Assistant Attorney General, Office of the Attorney General
Service List

I hereby certify I provided a copy of the within by e-file and/or hand delivery/ overnight courier/ first-class mail to each individual on the official service list for this docket on file with the Secretary of the Department of Telecommunications and Energy.

Dated at Westborough Massachusetts, this 5th day of October 2006.

NiSource
Corporate Services

Patricia M. French
Lead Counsel

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Westborough, Massachusetts 01581
(508) 836-7394
(508) 836-7039 (facsimile)
pfrench@nisource.com

October 6, 2006

VIA COURIER AND E-FILE

Mary L. Cottrell, Secretary
Department of Telecommunications and Energy
One South Station
Boston, MA 02110

Re: Bay State Gas Company, D.T.E. 06-36

Dear Ms. Cottrell:

Enclosed, pursuant to the Notice of Amendment filed on October 5th and for filing on behalf of Bay State Gas Company ("Bay State"), please find the following amended pages to be added to the record in this proceeding:

1. Bay State's Petition for Approval of System Protection Plan for Grandfather Overtakes, page 2;

2. Exh. BSG-1, the Testimony and Exhibits of Joseph A. Ferro, Bay State's Manager, Regulatory Policy, amended pages 9-18, and one line in Amended Exhibit JAF-3 (page 1 of 1);

3. Exhibit JAF-4 (redlined versions of Proposed M.D.T.E. No. 35 and M.D.T.E. No. 36): page 22 of 45 (Section 13, at page 13-13); page 24 of 45 (Appendix C); and page 26 of 45 (page 2). (These amendments would similarly be reflected in the clean versions of the proposed tariffs);

4. Amended Responses to DTE-1-2, DTE-1-25, DTE-2-2, DTE-3-7, DTE-3-8, AG-1-6, AG-1-7, AG-1-9, AG-1-10, AG-1-15, AG-1-18, AG-2-1, AG-2-2, AG-2-3, AG-2-8, AG-2-10, AG-3-7, SPR-1-2, SPR-1-11, SPR-1-13, SPR-1-15, HESS-1-15, HESS-1-23, HESS-2-4, HESS-2-6, and HESS-2-8; and,

5. Hess 1-16 SUPP.

Please do not hesitate to contact me at (508) 836-7394 or Robert L. Dewees, Jr., of Nixon Peabody LLP, at (617) 345-1316 with any questions concerning this filing.

Very truly yours,

Patricia M. French

cc: Julie Howley Westwater, Esq., Hearing Officer, DTE
Kevin Brannelly, Director, Rates and Revenue Requirements, DTE
George Yiankos, Director, Gas Division, DTE
Jamie M. Tosches, Esq., Office of the Attorney General
Service List, DTE 06-36

MOTION
OF BAY STATE GAS COMPANY
FOR APPROVAL OF
SYSTEM PROTECTION PLANNING STANDARD
FOR GRANDFATHERED OVERTAKES

Note: Amendment at page 2 only

II. SUMMARY OF PROPOSAL

Bay State's proposal is to introduce an incremental planning standard into the Company's resource planning process. The planning standard would provide for the inclusion of ~~thirty~~ thirteen percent (~~30~~13%) of grandfathered customer loads (design day requirements) in Bay State's requirements forecasted for planning purposes. Consistent with this proposal, Bay State today files modifications to its Distribution and Default Terms and Conditions in M.D.T.E. No. 35 that provide for the recovery of the costs attributable to the required resources. In the tariff, M.D.T.E. Nos. 35 and 36, Bay State proposes to recover these costs consistent with cost-causation principles: from grandfathered, capacity-exempt customers. Finally, Bay State presents changes to its nomination and balancing protocols also reflected in M.D.T.E. No. 35 that would allow the Company to monitor more closely the potential for unauthorized overtakes by grandfathered customers.

III. BACKGROUND

A. Bay State Plans its System to Serve Reliably its Firm Customers

Bay State acquires and manages upstream capacity resources needed to ensure reliable service for its customers. Upstream capacity resources include long-haul transportation from natural gas producing areas, such as the Gulf of Mexico, as well as short-haul transportation from storage areas in Pennsylvania, Ohio and New York, to Bay State's city gates, along with associated storage capacity. Bay State supplements these resources with third-party peaking

AMENDED PAGES TO

EXHIBIT BSG-1

**DIRECT TESTIMONY OF
JOSEPH A. FERRO**

Note: Amended pages 9 -18

unanticipated shutoff could result in damages to customers in the form of a loss of product or damage to equipment. If such consequences of a shutoff occurred, the Company could expect customers filing to hold the Company liable for their loss or petitioning the Department or the Governor's Office to continue to receive gas service.

Taking into consideration the impacts on Grandfathered customers, the imposition of cumbersome nomination changes for suppliers and the operational and liability concerns discussed previously, Bay State recommends that the Department consider an alternative means of resolving this matter. Bay State believes that the new approach outlined in the remainder of my testimony appropriately addresses the operational implications of unique level of Grandfathered loads on Bay State's system in a manner that is consistent with the Department's earlier findings on this issue.

Q. Please describe Bay State's proposal for planning criteria that satisfies the problem of overtakes by grandfathered customers.

A. Bay State's proposed new incremental capacity planning standard is based solely on the level of grandfathered load on its system. Specifically, Bay State proposes to maintain access to capacity sufficient to meet thirteen ~~thirty~~ percent (13%) of the design day requirements of grandfathered loads on its system at any given point in time. This incremental planning standard of 13% of grandfathered design day load is based on experiencing imbalances of over thirty percent (30%) in daily-metered pools. Based on updated customer extraction and design day calculations as of June 15, 2006 used in the Company's revised response to Hess 1-16, daily-metered load of grandfathered customers on tariff service represents approximately forty-three percent (43%) of total tariff grandfathered design day load. The remaining 57% is non-daily metered. Thus, the 30% imbalances in the daily metered pools translates into 13% of total grandfathered design day load (43% x 30% = 13%). Based on the current characteristics of the Company's supplier pools, non-daily metered pools are typically closer in balance than daily-metered pools.

This~~e~~ planning standard would translate into a level of required capacity that would substantially limit the increased operational risks of grandfathered supply service, which are significantly greater than any risks that Bay State's own system supply service presents. The costs of the capacity relied upon to meet this planning standard would be recovered solely from grandfathered customers through a charge whose revenues are credited to Bay State's Cost of Gas Adjustment ("CGA"). The capacity utilized by Bay State to meet the new planning standard would be sold in secondary markets when it is not utilized by Bay State, mitigating the overall cost of maintaining the new planning standard.

In addition, Bay State proposes to implement improvements to its existing reporting, relying primarily on existing systems and equipment installed on daily-metered customers, that will enable it to more closely monitor the occurrence of daily overtakes so that corrective action can be taken quickly. Changes to Bay State's nominating and balancing protocols will enable Bay State to acquire data necessary to establish unauthorized overtakes on a customer-specific basis. These reporting protocols are far more cost effective than installing the flow control equipment I discussed earlier.

The changes to the nomination and balancing protocols would not allow Bay State to monitor the daily overtakes of specific non-daily metered grandfathered customers. Also, based on the data provided in the Company's revised response to Hess 1-16, even though ~~T~~these customers represent approximately ninety percent (90%)~~one-half~~ of the Grandfathered tariff customer population on Bay State's system, the non-daily metered load represents ~~but~~ only fifty-seven ~~ten~~ percent (57%) of the design day load. In lieu of monitoring the specific usage of non-daily metered customers, Bay State proposes to establish the occurrence of unauthorized overtakes using its existing system of comparing required supplier nominations to actual supplier deliveries. To the extent that the Department is concerned with this element of Bay State's monitoring proposal, it could require Bay State to switch all existing non-daily metered grandfathered customers to daily-metered service or forego grandfathered status via the assignment of capacity to their supplier.

Q. **How did Bay State determine that the thirteen ~~y~~-percent planning standard is appropriate?**

A. The thirteen ~~y~~-percent capacity reserve level is based upon a combination of analytical results and reasoned business and operational judgment. Bay State reviewed the historic performance of competitive suppliers serving daily-metered ~~grandfathered~~ customers over the period November 2001 through December 2005. The results of this review indicate that Bay State experienced substantial delivery failures on a number of days during this period. Exhibit BSG-1 at Attachment JAF-2 provides analysis of the top daily supplier overtakes in daily metered pools during the period. As previously mentioned, ~~T~~these data indicate that on three occasions in the four-year period, supplier overtakes exceeded thirty percent in one of the Company's divisions, and that these daily metered pools comprise approximately 43% of grandfathered load. By virtue of the fact that the non-daily-metered grandfathered imbalances and the daily-metered non-grandfathered imbalances are excluded from the derivation of the incremental planning standard, the resulting planning standard is conservative.

The three occasions of daily imbalances over thirty percent in four years is a very high incidence rate compared to the Bay State's one-in-twenty-five-year planning standards applicable to design weather. Moreover, these data are post-imbalance trading whereby a supplier could reduce its overtake by trading with a supplier that had an undertake on the same day. The observed level of overtakes would have been even greater if daily imbalance trading had been excluded. The primary concern with unauthorized overtakes by grandfathered customers is the possibility that they may occur on a design day when Bay State's resources are fully utilized and upstream pipelines are stressed. Bay State did not experience a design day during the analysis period, however, many of the most significant overtakes occurred on cold-weather days when pipeline operations are typically more constrained and secondary deliveries are more likely to be curtailed.

A final factor that Bay State considered was the allocation of risk across suppliers serving its Grandfathered customers. Presently, 9 suppliers have Grandfathered customers in their pools; customer design day load ranging from less than 1 Dth to 2,248 Dth and pools ranging in size from 27 to 8,533 Dth of design day load. The thir~~ty~~een percent of the 57,674 ~~58,846~~ Dth of design day load of all Grandfathered customers, or 7,440 ~~17,654~~ Dth, would cover performance failures by the 4 ~~22~~ largest Grandfathered customers of these suppliers. While Bay State would not be able to redress the concurrent failure of all supplies to Grandfathered customers, the Company believes that the vast majority of the existing operational risk would be mitigated under its proposal.

Q. **How will the new planning standard affect Bay State's resource planning process?**

A. Presently, Bay State analyzes its resource needs on the basis of the design weather requirements of its sales and non-grandfathered transportation customers. The implementation of the new planning standard would contribute to a resource need applicable to a limited portion of the requirements of Grandfathered transportation customers in addition to Bay State's other resource needs. This need would be factored into Bay State's integrated resource planning process increasing the quantity of capacity necessary to maintain reliable service. The costs of the incremental capacity would be borne by Grandfathered customers. Based on existing levels of Grandfathered customer loads, the incremental planning standard would translate into a capacity need of ~~17,654~~ 7,440 Dth.

Q. Once the reserve capacity is in place, are there any consequences for specific customers that fail to deliver?

A. Yes. Bay State recommends that customers who demonstrate that they have not acquired sufficiently reliable service be subject to future assignment of capacity. In particular, any Grandfathered customer that experiences an unauthorized overtake that exceeds thirty percent on a critical operating day would be subject to permanent assignment of capacity. This provides an important incentive for customers to ensure that their suppliers are able to provide reliable service. Limiting the assignment to overtakes that exceed thirty percent on critical days reflects the capacity acquired to satisfy the thirteen ~~y~~-percent of total grandfathered design day reserve and further protects customers from the potential consequences associated with under-deliveries by suppliers of their requirements on the majority of days during the year. Finally, permanently assigning capacity to customers who overtake by greater than 30% and removing their requirements from the basis of determining the cost of the thirteen ~~y~~-percent reserve, more directly addresses the cost imposition of certain customers within the Grandfathered group.

Q. Have you prepared an estimate of the cost impact of Bay State's proposal?

A. Yes. REVISED Exhibit BSG-1 at Attachment JAF-3 (October 2006) provides a sample calculation of the impact of Bay State's proposal. The aggregate Grandfathered peak load on Bay State's system is currently ~~58,846~~ 57,674 Dth, thirteen percent of which is approximately 7,440 Dth. The annual cost of the capacity required to satisfy the thirteen ~~y~~-percent planning standard is $980,659 ~~2.3 million~~ based on the average capacity cost of Bay State's existing portfolio. This translates into a charge of ~~$0.182~~ $0.102 per Dth based on Bay State's proposal to recover the full costs from grandfathered customers. To the extent that the size of the pool of grandfathered loads increases or decreases, the charge should remain relatively stable as the level of capacity associated with the planning standard will adjust commensurately.

Q. What are the benefits to customers of Bay State's proposed permanent resolution to the issues created by Grandfathered loads?

A. The primary benefit of Bay State's proposal is that it allows Grandfathered customers to continue to enjoy the financial benefits of firm transportation service exempt from capacity assignment requirements.

While Grandfathered customers would bear additional cost under the new planning standard, the impact on the total cost of firm gas service would be approximately ~~0.6% ($2.3 m / $400 m)~~ 0.2% ($1.0 MM / $400 MM). Compared with the benefits that these customers realize under Grandfathered status, the cost is far less than would be required under the implementation of an alternative system based on the installation of load control equipment. Moreover, it eliminates the risk of shutoff to an important class of customers that are required to meet essential needs and those whose operations support the Massachusetts economy. Depending on the circumstances, the new planning standard may ease the difficulty with which Grandfathered customers may return to sales service.

Q. Are tariff modifications appropriate to implement Bay State's proposal?

A. Yes. Bay State has revised the capacity assignment provisions of Section 13 of M.D.T.E. No. 35, to incorporate the changes associated with its proposal. Specifically, Section 13.12 has been added to recover the costs associated with the planning standard from Grandfathered transportation customers. In addition Section 13.13 has been added to specify the methodology Bay State will employ to monitor Grandfathered customer overtakes on Critical Days. Required tariff changes to the CGAC provide for the crediting of all revenues recovered from Grandfathered customers pursuant to the new charge reflected in Section 13.12 to gas costs recoverable from other customers.

Red-lined tariff pages providing all of the required changes to implement the proposal are provided as REVISED Exhibit BSG-1 at Attachment JAF-4 (October 2006).

Q. Why are the new resource planning standard and proposed tariff changes in the public interest?

A. Bay State's proposal is fair and equitable to Grandfathered customers as well as other firm customers: the increased costs of the new planning standard will be borne by Grandfathered customers eliminating the possibility of cost shifting. The associated cost increases to Grandfathered customers are reasonable in view of the benefits these customers receive, including the exemption from mandatory capacity assignment. The cost impact of Bay State's proposal is lower than any feasible alternative approach that would entail the installation of load control equipment at customer locations.

Q. When should the proposal be implemented?

A. Modified Terms and Conditions should be implemented February ~~September~~ 1,st 2007 ~~of this year~~ to allow Bay State to align its portfolio with the planning standard and reflect the impact ~~in both its Peak Period Cost of Gas Adjustment filing on September 15, 2006, and~~ in the course of its IRP proceeding, which will commence with the Company's filing to be submitted by October 22, 2006.

Q. Does this conclude your testimony?

A. Yes, it does.

Capacity Exempt Customer Reliability Charge
Example Calculation

Row	Description		Amount		Calculation
(1)	Capacity Exempt Customer Peak Day		57,674	Dth	
(2)	Daily Metered Cap Exempt Peak Day		24,800		43% x (1)
(3)	Reliability Factor per D-M Cap Exempt		30%		
(4)	Reliability Capacity		**7,440**	Dth	(2) x (3)
(5)	Reliability Factor per Cap Exempt Peak Day			**13%**	(4) / (1)
(6)	Average Annual Unit Capacity Cost		131.81	per Dth	
(7)	Reliability Costs	$	980,659		(4) x (6)
(8)	Capacity Release / OSS Margin Revenues	$	(6,407,187)		
(9)	Total System Design Day		504,151	Dth	
(10)	Capacity Release / OSS Credit	$	(94,553)		(8) x ((4) / (9))
(11)	Prior Period Under / (Over) Recovery	$	-		
(12)	Total CECRC Allowable Costs for Period	$	886,106		(7) + (10) + (11)
(13)	Capacity Exempt Customer Throughput (Therms)		86,722,280		
(14)	CECRC Charge per therm	$	**0.0102**		(12) / (13)

DISTRIBUTION AND DEFAULT SERVICE TERMS AND CONDITIONS

13.12.2 Each year, the Company shall calculate a CECRC rate per therm applicable to all Capacity Exempt Customer throughput for the annual period beginning November 1. The CECRC rate per therm and the associated derivation shall be set forth in Appendix C to these Terms and Conditions.

13.12.3 The CECRC rate per therm shall be calculated as follows:

(1) Allowable CECRC costs shall equal the sum of the following:

(a) The product of the total Capacity Exempt Customer *Daily-Metered Service* peak day requirements, determined prior to November 1, the system average annual unit capacity cost, and a factor of 30% (thirty percent).

(b) A capacity release and off-system sales revenue credit equal to the total projected annual capacity release and off-system sales margin revenues for the annual period beginning November 1 multiplied by the ratio of *30% of* the total Capacity Exempt Customer *Daily-Metered Service* peak day requirements to the total system peak day requirements.

(c) Any difference, positive or negative, between the costs of the CECRC as established for the previous annual period November 1 through October 31 and the actual collections from the application of the CECRC rate to Capacity Exempt Customer throughput for the corresponding period.

13.12.4 The total revenues recovered pursuant to the CECRC shall be credited to the Company's CGA costs in accordance with M.D.T.E. No. 36.

13.13 Monitoring Capacity Exempt Customer Overtakes

13.13.1 Overtakes associated with Capacity Exempt Customer loads threaten the reliability of Bay State's distribution system. Therefore, the Company shall monitor Supplier overtakes associated with Capacity Exempt Customer loads on Critical Days.

13.13.2 All Capacity Exempt Customers served by a Supplier that experiences an overtake on a Critical Day that exceeds thirty percent (30%) of the aggregate Gas Usage of Capacity Exempt Customers within its Aggregation Pool shall lose their status as exempt from the mandatory capacity assignment provisions of these Terms and Conditions. In order to determine whether a Supplier has exceeded the allowed 30% overtake for Capacity Exempt Customer loads, the Company shall perform the following calculations

DISTRIBUTION AND DEFAULT SERVICE TERMS AND CONDITIONS

APPENDIX C

Capacity Exempt Customer Reliability Charge

Row	Description	Amount	Calculation
(1)	Daily-Metered Capacity Exempt Customer Peak Day	XX Dth	
(2)	~~Average Annual Unit Capacity Cost~~Factor	~~$__ per Dth~~30%	
	~~Factor~~Reliability Capacity	~~30%~~	(1) x (2)
	Average Annual Unit Capacity Costs	$__ per Dth	
(5~~4~~)	Reliability Costs		(~~1~~3) x (~~2~~4) ~~x (3)~~
(6~~5~~)	Capacity Release / OSS Margin Revenues	$__	
(7~~6~~)	Total System Design Day	XX Dth	
(8~~7~~)	Capacity Release / OSS Credit		(~~5~~6) x ((~~1~~3)/(6~~7~~))
(9~~8~~)	Prior Period Under / (Over) Recovery	$__	
(10~~9~~)	Total CECRC Allowable Costs for Period	$__	(4~~5~~) + (~~7~~8) + (~~8~~9)
(11~~0~~)	Capacity Exempt Customer Throughput	Dth	
(12~~1~~)	CECRC Charge per therm	$__	(~~9~~10) / (11~~0~~)

COST OF GAS ADJUSTMENT CLAUSE

3.0 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, other gas supply expense incurred to procure and transport supplies and bad debt percent (from the last general rate case) applied to allowable CGAC costs for the forecast period, 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 filings outlined in Section 12.0.

4.0 Effective Date of Gas Adjustment Factor

The date on which the seasonal Gas Adjustment Factors ("GAF") become effective shall be the first day of the first month of each season as designated by the Company. Unless otherwise notified by the Department, the Company shall submit GAF filings as outlined in Section 12.0 of this clause at least 45 days before they are to take effect.

5.0 Definitions

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

(1) **Annual Threshhold** - A threshold level of margins, established annually and separately for Capacity Release, Interruptible Sales and Off-System Sales, based on the twelve months ended April 30 each year, the level above which the Company retains 25% of such margins.

(2) **Bad Debt Expense** - is the uncollectable expense attributed to the Company's gas costs plus allowable working capital derived from the gas cost portion of bad debt.

(3) **Base Load Requirements** - The annual quantity of gas supply needed to satisfy the lowest level of firm demand based on the average July and August loads.

(4) **Capacity Exempt Customer Reliability Charge ("CECRC") Revenues** – The revenues from billing the CECRC to capacity exempt firm transportation customers for the cost of capacity resources needed for system reliability and based on *13~~3~~0*% of the capacity exempt design day requirements.

(4~~5~~) **Capacity Release Revenues** - The economic benefit derived from the sale of upstream capacity.

(~~5~~6) **Carrying Charges** - Interest expense calculated on the average monthly balance using the consensus prime rate as reported in the *Wall Street Journal*.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
FIRST SET OF INFORMATION REQUESTS FROM THE D.T.E.

D.T.E. 06-36

Date: June 27, 2006
Amended: October 6, 2006

Responsible: Joseph A. Ferro, Manager, Regulatory Policy

DTE 1-2: Has Bay State made arrangements for the necessary capacity to fulfill the supply requirements of grandfathered customers? If so, provide all details and documents related thereto. Provide all details on the cost of the supply.

Response: No. The purpose of the instant filing is to address an incremental planning standard that would permit Bay State to provide up to 13~~0~~% of the possible level of total grandfathered overtakes on a critical day, which are based on, and would cover up to, 30% of daily metered grandfathered overtakes on a critical day. Bay State has not "made arrangements" for this 13~~0~~% planning standard and will not do so unless and until it has Department approval of the proposal and its long-term resource plan requires it to do so.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
FIRST SET OF INFORMATION REQUESTS FROM THE D.T.E.

D.T.E. 06-36

Date: June 27, 2006
Amended: October 6, 2006

Responsible: Joseph A. Ferro, Manager, Regulatory Policy

DTE 1-25: Refer to Exh. BSG-1, at 10 lines 13-14. If the non-daily metered grandfathered customers represent only ten percent of the load, how do overtakes by those customers threaten the reliability of Bay State's distribution system? Explain in more detail the "existing system of comparing required supplier nominations to actual supplier deliveries" for non-daily metered grandfathered customers.

Response: The Company is more concerned over daily imbalances resulting from supplier performance occurring in daily metered pools rather than non daily metered pools for a few reasons. First, the burden of forecasting a non-daily metered pool's daily requirement is Bay State's. As long as suppliers nominate gas volumes on a non-critical day within the 10% tolerance bandwidth of the Adjusted Target Volume ("ATV") that Bay State derives through use of its algorithm, they are not exposed to any daily imbalance penalties. Second, in each marketer's Supplier Service Agreement, he has elected a Predetermined Allocation Method that makes non-daily metered pools whole first, assigning any shortages automatically to the daily metered pools. Finally, because non-daily metered pools are trued up to actual consumption over thirty days after the Gas Day has concluded, an overtake by a non-daily metered customer will not be evident until well after the day in question.

Notwithstanding the assumed or perceived minimal imbalances in non-daily metered pools, ~~While~~ non-daily metered grandfathered customers represent ~~only ten~~fifty-seven percent of the daily grandfathered load, and a shortfall of grandfathered load on a Critical Day could put the Company's system at risk. Further, the gas use of a grandfathered non-daily metered customer whose actual consumption on a given day exceeds the historic patterns used to forecast their daily requirement could cause a substantial imbalance in the pool.

Each non-daily metered pool is cashed out at the end of each month by comparing the algorithm results reflecting the forecasted weather or effective degree days (EDD) to the actual EDD. But as previously mentioned, a true up to actual consumption is not available until over 30 days after the Gas Day is over. Real time monitoring of a non-daily metered account was never a factor considered when non-daily metered transportation service was collaboratively designed.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
FIRST SET OF INFORMATION REQUESTS FROM SPRAGUE ENERGY, INC.
D.T.E. 06-36

Date: September 13, 2006
Amended: October 6, 2006

Responsible: Joseph A. Ferro, Manager Regulatory Policy and Francisco C. DaFonte, Director, Energy Supply Services

DTE 2-2 Assuming the Department were to approve the Petition:

(a) provide a list of all actions that Bay State would need to undertake to implement the proposal.

(b) indicate the specific time frame for each action.

(c) indicate whether Bay State considers any of the actions to be critical for the winter of 2006-07. If so, provide supporting documentation for that assessment.

(d) identify the likely providers, if any, of both capacity and supply that Bay State would contact to implement the proposal.

(e) identify any additional regulatory approvals that may be required to implement the proposal.

RESPONSE: (a) Bay State would first assess its total system requirements given the 13~~0~~% reserve capacity planning process. Bay State would do this separately for the Tennessee system (serving the Springfield and Lawrence Divisions) and the Algonquin system (serving the Brockton Division). As shown in the attachment to the response to Hess 1-2, Bay State has sufficient assets to cover the capacity reserve demand on Tennessee but would require approximately ~~6~~3,6000~~0~~ Dth of additional capacity on the Algonquin system (24,126 x 13% + deficiency of 496). Consistent with its resource procurement process, Bay State would seek bids for the capacity reserve requirements in the Brockton Division. To the extent that this incremental resource and associated costs would be identified prior to November 1, 2006, the Company's CECRC would reflect capacity costs including this resource.

(b) The Company would undertake the above actions immediately upon receiving an order.

REVISED (c) Bay State considers the shortfall in its Brockton Division to be of a critical nature. As shown in Amended Attachment DTE 2-2 (c) the Company would be approximately ~~7~~3,~~7~~600 Dth short on Design Day in its Brockton Division.

(d) Bay State has a list of more than forty counterparties with which it does business on a fairly regular basis. Bay State would conduct an RFP process that would include these forty counterparties as well as others that may be added.

(e) Department approval for the Company's specific tariff changes filed in this proceeding would be required. These changes include the proposed CECRC tariff and specific rate filing for implementation on December 1, 2006, as well as revisions to its Delivery and Default Service Terms and Conditions and Cost of Gas Adjustment Clause. In addition, regulatory approval may be needed for the incremental resource acquisition should it be for greater than one year.

Attachment DTE 2-2c
Amended 10-06-06

Bay State Gas Company
Comparison of Capacity & Demand Requirements By Division
(MMBtu)
2007-2010 Design Day

Brockton Division

	2006-2007	2007-2008	2008-2009	2009-2010
Total Pipeline	135,449	135,449	135,449	135,449
Total Storage	27,815	27,815	27,815	27,815
Total Peaking	74,000	74,000	74,000	74,000
Total Capacity	237,264	237,264	237,264	237,264
Total Demand	261,886	264,505	267,150	269,821
Grandfathered Requirements	24,126	24,126	24,126	24,126
13% Reserve	3,136	3,136	3,136	3,136
Net Demand*	240,896	243,515	246,160	248,832
Deficiency	3,632	6,251	8,896	11,568

Springfield/L

	2
Total Pipeline	
Total Storage	
Total Peaking	
Total Capacity	
Total Demand	
Grandfathered Requirement	
13% Reserve	
Net Demand*	
Deficiency	

*: Reflects sales plus non-grandfathered transportation demand plus 13% of grandfathered demand

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
THIRD SET OF INFORMATION REQUESTS FROM THE D.T.E.
D.T.E. 06-36

Date: September 1, 2006
Amended: October 6, 2006

Responsible: Joseph A. Ferro, Manager Regulatory Policy

DTE 3-7: Calculate a reserve comparing the absolute value of imbalance specific to grandfathered customers compared to the design MDQs of the grandfathered pool.

RESPONSE: As noted by Mr. Ferro in his prepared direct testimony at page 11, the level of the capacity exempt customer reserve is based on a number of factors including, but not limited to, the level of overtakes noted in Exhibit JAF-2. Attachment DTE 3-7 restates the daily-metered overtakes for the top twenty days on an absolute value basis by including the supplier deliveries for those suppliers with undertakes in the determination of net overtake for each Division. While the percentage overtake on most days is reduced under this methodology, significant overtakes are still shown for many days. In particular, the percentage overtake of the daily metered pools by Division on two days during the four-year period is above 30% and is between 20% and 30% on four additional days. Therefore, Bay State would not change its assessment of the appropriate level of reserve of 13~~30~~% of grandfathered design day based on the absolute value of imbalances of grandfathered customers. The 13% incremental planning standard is derived from this same 30% of observed imbalances of the daily metered pools, adjusted to recognize that daily metered grandfathered design day only is only 43% of total grandfathered design day of tariff customers.

Note that grandfathered customers' MDQs are typically calculated only for informational purposes, such as for regulatory discovery, since the Company does not assign capacity for these customers. Any calculation of a MDQ would be based on the customer's base load and use per degree day factors in the Company's Customer Information System (CIS). Therefore, Bay State does not have the design MDQs for grandfathered customers on a historical basis. Moreover, any daily imbalance should be based on the associated confirmed nomination rather than on the design MDQ.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
THIRD SET OF INFORMATION REQUESTS FROM THE D.T.E.
D.T.E. 06-36

Date: September 8, 2006
Amended: October 6, 2006

Responsible: Joseph A. Ferro, Manager Regulatory Policy

DTE 3-8: Calculate the Customer Reliability Charge assuming a reserve of: (a) ten percent, (b) one percent, and (c) the calculation amount from DTE 3-7, above. In addition for each of these three amounts, calculate the Charge assuming the Charge is spread over all customers, not just grandfathered customers. Indicate whether Bay State would agree that the proceeding would have to be re-noticed if the Charge were to be assessed on all customers, not just grandfathered.

RESPONSE: See Amended Attachment DTE 3-8(a), DTE 3-8(b) and DTE 3-8(c) for the calculations of the Capacity Exempt Customer Reliability Charge under the requested reserve percentage assumptions, and within each reserve assumption a CECRC applicable to grandfathered customers, only, and all firm customers.

Please note that under the Company's initially proposed CECRC at a Reliability Cost factor of 30%, 100% of Capacity Release and Off-system Sales margins are credited at the ratio of Capacity Exempt design day to total system design day. Under these various requested assumptions, including the Company's revised CECRC at a Reliability Factor of 13% of grandfathered design day, the CECRC calculations reflect the allocation of the Capacity Release and Off-system Sales Credit at the Reliability Capacity, rather than the total Capacity Exempt Peak Day, to total system design day~~, adjusted by the ratio of the requested lower reserve percentage to 30%~~. Without this adjustment, the allocated credit would be disproportionate to the Reliability Costs.

Notwithstanding that Mr. Ferro is not a lawyer, he will indicate on behalf of Bay State that it is Bay State's view that the initial notice in this proceeding was sufficient to notify customers that a proceeding was pending that may affect the rates and charges of transporting or firm customers. The initial notice, which was published in at least one newspaper of general circulation, indicated that grandfathered customers may be responsible for the reliability charge under Bay State's proposal, which means that the capacity costs of all other customers may be initially reduced by an equivalent amount. In determining whether Bay State's proposal is in the public interest, the Department may determine that an alternative rate design is appropriate. The initial notice was sufficient for interested parties to determine the nature of the proceeding and to appear if they so chose. A rate design change does not require re-noticing of the proceeding, in Bay State's view.

At a 10% Reserve Factor

Capacity Exempt Customer Reliability Charge
Example Calculation

Row	Description		Amount		Calculation
(1)	Capacity Exempt Customer Peak Day		57,674	Dth	Revised 10-06
(2)	Reliability Factor per Cap Exempt Peak Day		10%		
(3)	Reliability Capacity		5767		
(4)	Average Annual Unit Capacity Cost		131.81	per Dth	
(5)	Reliability Costs	$	760,148		(3) x (4)
(6)	Capacity Release / OSS Margin Revenues	$	(6,407,187)		
(7)	Total System Design Day		504,151	Dth	
(8)	Capacity Release / OSS Credit	$	(73,292)		(6) x ((3) / (7))
(9)	Prior Period Under / (Over) Recovery	$			
(10)	Total CECRC Allowable Costs for Period	$	686,856		(5) + (8) + (9)
(11)	Capacity Exempt Customer Throughput (Therms)		86,722,280		
(12)	Total Firm Customer Throughput (Therms)		473,883,120		
	CECRC Charge per therm:				
(13)	To Capacity Exempt Customers	$	0.0079		(10) / (11)
(14)	To All Firm Customers	$	0.0014		(10) / (12)

At a 1% Reserve Factor

Capacity Exempt Customer Reliability Charge
Example Calculation

Row	Description		Amount		Calculation
(1)	Capacity Exempt Customer Peak Day		57,674	Dth	Revised 10-06
(2)	Reliability Factor per Cap Exempt Peak Day		1%		
(3)	Reliability Capacity		577		
(4)	Average Annual Unit Capacity Cost		131.81	per Dth	
(5)	Reliability Costs	$	76,054		(3) x (4)
(6)	Capacity Release / OSS Margin Revenues	$	(6,407,187)		
(7)	Total System Design Day		504,151	Dth	
(8)	Capacity Release / OSS Credit	$	(7,333)		(6) x ((3) / (7))
(9)	Prior Period Under / (Over) Recovery	$			
(10)	Total CECRC Allowable Costs for Period	$	68,721		(5) + (8) + (9)
(11)	Capacity Exempt Customer Throughput (Therms)		86,722,280		
(12)	Total Firm Customer Throughput (Therms)		473,883,120		
	CECRC Charge per therm:				
(13)	To Capacity Exempt Customers	$	0.0008		(10) / (11)
(14)	To All Firm Customers	$	0.0001		(10) / (12)

Attachment DTE 3-8 (c)
Amended 10-06-06

At 13% Factor (per DTE 3-7)
[30% DM x 43% of GF = 13%]

Capacity Exempt Customer Reliability Charge
Example Calculation

Row	Description		Amount			Calculation
(1)	Capacity Exempt Customer Peak Day		57,674	Dth		Revised 10-06
(2)	Daily Metered Cap Exempt Peak Day		24,800			43% x (1)
(3)	Reliability Factor per D-M Cap Exempt		30%			
(4)	Reliability Capacity		7,440	Dth		(2) x (3)
(5)	Reliability Factor per Cap Exempt Peak Day				13%	(4) / (1)
(6)	**Actual** Annual Unit Capacity Cost	$	**130.97**	per Dth		
(7)	Reliability Costs	$	974,410			(1) x (2) x (3)
(8)	Capacity Release / OSS Margin Revenues	$	(6,407,187)			
(9)	Total System Design Day		504,151	Dth		
(10)	Capacity Release / OSS Credit	$	(94,553)			(8) x ((4) / (9)
(11)	Prior Period Under / (Over) Recovery	$	-			
(12)	Total CECRC Allowable Costs for Period	$	879,856			(4) + (7) + (8)
(13)	Capacity Exempt Customer Throughput (Therms)		86,722,280			
(14)	Total Firm Customer Throughput (Therms)		473,883,120			
	CECRC Charge per therm:					
(15)	To Capacity Exempt Customers	$	**0.0101**			(12) / (13)
(16)	To All Firm Customers	$	**0.0019**			(12) / (14)

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
FIRST SET OF INFORMATION REQUESTS FROM THE ATTORNEY GENERAL
D.T.E. 06-36

Date: June 28, 2006
Amended: October 6, 2006

Responsible: Joseph A. Ferro, Manager Regulatory Policy

AG 1-6: Please refer to Exh. BSG-1 at 11-12. Provide the reason for the Company's choice to reserve thirteen ~~y~~ percent as the contingency reserve instead of some higher percentage when the Company's data indicated that the past overtakes exceeded thirty percent.

RESPONSE: In Bay State's business judgment, and based on its expertise in the industry as well as its knowledge of its portfolio, 13~~0~~ percent was determined to be a reasonable planning standard and appropriately balances reliability and cost considerations. The 13% of total grandfathered design day load as the planning standard is based on 30 percent overtakes of daily metered grandfathered customers, which represent 43% of all grandfathered load under firm tariffs. Such judgment also takes into account that the Company's proposed provisions in Section 13.13.2 of the Distribution and Default Service Terms and Conditions, where a Customer who overtakes by greater than 30% shall lose its capacity exemption status, should help limit the incidences of overtakes of greater than 30%.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
FIRST SET OF INFORMATION REQUESTS FROM THE ATTORNEY GENERAL
D.T.E. 06-36

Date: June 28, 2006
Amended: October 6, 2006

Responsible: Joseph A. Ferro, Manager Regulatory Policy

AG 1-7: Refer to Exh. BSG-1 at 11-12.

i. Please explain how this analysis differs from that used to arrive at the ten percent contingency reserve in D.T.E. 02-75, and;
ii. Please state the reason(s) for Bay State's use of two different analytical methods.

RESPONSE: The difference in analysis and justification for the two methods rests in Bay State's greater understanding of the issue and the regulatory response to the issue in examining the alternatives in the last four years since D.T.E. 02-75 was issued. While the ten percent contingency reserve proposed in D.T.E 02-75 attempted to address the reliability need for any circumstance that may arise, and which the design day standard does not capture, the Company had acknowledged at the time, and continues to recognize, that the system reliability risk is primarily caused by the grandfathered load on the system. Bay State believes that a ~~thirty~~ thirteen percent planning standard related only to the grandfathered customer load is more closely linked to the harm that the planning standard is designed to address. This means it is a more closely tailored and therefore more reasonable response to the problem.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
FIRST SET OF INFORMATION REQUESTS FROM THE ATTORNEY GENERAL
D.T.E. 06-36

Date: June 28, 2006
Amended: October 6, 2006

Responsible: Joseph A. Ferro, Manager Regulatory Policy

AG 1-9: Describe the capacity procurement process that Bay State will use to acquire capacity for grandfathered customers, and state whether the Company will procure capacity for each individual grandfathered customer, for each division, or in some other manner.

RESPONSE: Bay State will incorporate the need for firm capacity to satisfy ~~30~~13% of grandfathered design day load in its Forecast and Supply Plan process filed with the Department. Capacity procurement will not be made for individual grandfathered customers, but rather capacity to meet this reliability requirement will be procured as part of its resource plan to satisfy total system requirements. Please also see Bay State's response to DTE 1-22.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
FIRST SET OF INFORMATION REQUESTS FROM THE ATTORNEY GENERAL
D.T.E. 06-36

Date: June 28, 2006
Amended: October 6, 2006

Responsible: Joseph A. Ferro, Manager Regulatory Policy

AG 1-10: Please refer to Exh. BSG-1 at 9, lines 9-21; BSG-1 at 14. Explain in detail the methods that Bay State will use to distribute costs to grandfathered customers through the Company's Cost of Gas Adjustment ("CGA").

RESPONSE: Bay State has proposed to charge all grandfathered customers at a uniform per unit cost calculated as the Capacity Exempt Customer Reliability Charge (CECRC). Such a charge will reflect costs based on ~~30~~13% of grandfathered design day requirements times the average cost of system capacity. See Amended Attachment JAF-3 and Appendix C of Amended Attachment JAF-4.

The revenues generated from the application of the CECRC will be credited to the system Peak Period demand costs charged through the CGA. In Section 6.0, Peak Demand Factor Formula, of the proposed CGA Clause, such revenues shown as CECRCR are deducted from Peak Period forecast demand costs. Further, in Section 9.0 Reconciliation Adjustments, in subsection (1) (a) vii, it provides for the crediting of these revenues to the actual allowable demand costs included in the CGA.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
FIRST SET OF INFORMATION REQUESTS FROM THE ATTORNEY GENERAL
D.T.E. 06-36

Date: June 28, 2006
Amended: October 6, 2006

Responsible: Joseph A. Ferro, Manager Regulatory Policy

AG 1-15: Please refer to Exh. BSG-1 at 11, line 3-10. Will Bay State use this data in its cost allocation methodology and if not, then explain why not.

RESPONSE: The phrase "cost allocation methodology" is vague. Bay State allocates costs for many purposes and under numerous cost recovery scenarios. The data referenced was used to determine, in part, the proposed ~~30~~13% of grandfathered design day requirements. The application of the ~~30~~13% to grandfathered requirements is the basis for assigning system capacity costs to this group of customers.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
FIRST SET OF INFORMATION REQUESTS FROM THE ATTORNEY GENERAL
D.T.E. 06-36

Date: June 28, 2006
Amended: October 6, 2006

Responsible: Joseph A. Ferro, Manager Regulatory Policy

AG 1-18: Please illustrate the mechanics of the Company's proposal by using actual volumes and hypothetical costs for 2004/05 with reconciliation in 2005/06. Include all supporting calculations, workpapers and assumptions. Please provide the calculations in the form a working Excel spreadsheet model.

RESPONSE: The Company's proposal involves charging a per therm unit charge to all grandfathered customers for the cost of capacity associated with ~~30~~13% of grandfathered design day, and crediting such costs through the CGA. As an example, presented in Amended Attachment JAF-3, using current (~~winter 2005~~ June 2006) grandfathered design day and the system average cost of capacity reflected in the 2005-06 Peak Period CGA filing, the Company calculated total CECRC costs to be recovered of $~~1,579,082~~886,106. These costs, updated with current grandfathered design day and the current cost of system capacity, will be considered actual costs starting in November of the Nov – Oct recovery period, and assigned to each month evenly (1/12 of annual costs). The monthly assigned costs will be compared to the actual collections (GF throughput x CECRC) each month, the difference of which will be the monthly under/over collection. The monthly actual costs will be credited to firm sales customers through the CGA mechanism. At the end of the annual recovery period any under or over collection of the $~~1,579,082~~886,106 will be reflected in the derivation of the next year's CECRC. (See Line ~~8~~ 11 of Amended Attachment JAF-3.)

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
SECOND SET OF INFORMATION REQUESTS FROM THE ATTORNEY GENERAL
D.T.E. 06-36

Date: July 21, 2006
Amended: October 6, 2006

Responsible: Joseph A. Ferro, Manager Regulatory Policy

AG 2-1: Please refer to Exhibit ("Exh.") AG-1-15. "Cost allocation methodology" means the method of assigning costs to specific customer classes based on cost causation principles, *i.e.* "that cost responsibility must follow cost incurrence." [1] *See* D.T.E. 98-32-B at 31; *Bay State Gas Company*, D.T.E. 02-75-A, at 5. Please respond to the original question.

[1] For example, the Company uses cost allocation methods to develop its class specific Cost of Gas Adjustment ("CGA") rates for recovery of capacity costs from sales customers.

RESPONSE: The data referred to in Exh. BSG-1 at 11, lines 3-10, was observed and subsequently used to establish a reasonable percentage of grandfathered load as the level of resource needed to be available to help protect against disruption of service to the Company's firm sales and non-grandfathered customers in the event of grandfathered customers overtaking on a Critical (or OFO) Day. In particular, the observed level of daily-metered imbalances of 30% multiplied by the proportion of grandfathered load that is daily metered, *i.e.*, 43%, yields the proposed incremental planning standard of 13% of total grandfathered design day load. This percentage of grandfathered customers' design day load of ~~30~~13% was first used to determine the level of capacity costs associated with this level of reliability resources, and then such costs have been assigned directly to the group of customers causing the need for the Company to incur these costs. The charging for this capacity that is needed to be available on design day, at the average system cost of capacity, is ultimately deducted from the total system capacity costs, similar to deducting the capacity assignment revenues associated with the mandatory assignment of capacity to Suppliers on behalf of the non-grandfathered customers.

For deriving Gas Adjustment Factors through the CGA mechanism, which is performed on a forecast basis, the peaking resources would be reduced by ~~30~~13% of grandfathered design day before running the dispatch model, which in turn feeds the CGA model. Through the reconciliation process, the CECRC revenues would be credited to actual system capacity costs, reducing the actual capacity costs charged to sales customers.

In sum, and as indicated in response to AG-1-15, the referenced data is used to allocate costs to the group of customers causing the Company to incur such costs insofar as ~~30~~13% of grandfathered design day determines the costs charged only to grandfathered customers, as such costs are credited to the system capacity costs charged to sales customers.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
SECOND SET OF INFORMATION REQUESTS FROM THE ATTORNEY GENERAL
D.T.E. 06-36

Date: July 21, 2006
Amended: October 6, 2006

Responsible: Joseph A. Ferro, Manager Regulatory Policy

AG 2-2: Please provide a detailed outline of Bay State Gas Company's ("Bay State" or "Company") CGA cost allocation methodology for allocating the cost of additional transmission capacity to serve grandfathered customers. If the Company cannot do so, explain why not?

RESPONSE: The response below first provides a description of the Bay State CGA cost allocation methodology and then an explanation of how capacity associated with ~~30~~13% of grandfathered load is treated in the CGA process.

Bay State Gas Company's CGA Cost Allocation Methodology:

Bay State's CGA cost allocation methodology uses a normal weather year's monthly dispatch of supplies and utilization of capacity to allocate system resources and the associated capacity costs to each rate class (including non-grandfathered transportation classes). The resulting assigned costs to each rate class are aggregated to high load factor (low winter) and low load factor (high winter) class groupings. The allocation of resources and associated costs are based on how each rate class's monthly demand during an annual period fits into the Company's load duration curve. The load duration curve, and customers' demand, is separated into two portions; base load and "remaining load".

The base load portion of each rate class's demand is satisfied by, and thus assigned, the Company's base load resources, including the associated capacity costs. The base load resources typically consist exclusively of long-haul pipeline resources. The "remaining load" is served by a combination of resources including pipeline not used to satisfy base load, underground storage, winter service supplies, peaking supplies and on-system LNG and propane production. The capacity costs associated with these resources are assigned to each customer class based on each class's percentage of design day demand less the base load use (on design day) to total system remaining design day demand. The seasonal allocation of these capacity costs are determined by assigning the capacity costs to months using a Proportional Responsibility (PR) allocator. The PR derives monthly percentages based on the utilization or sendout of the "remaining load" resources in each month.

Treatment of Capacity re: ~~30~~13% of Grandfathered Load:

Bay State Gas Company's CGA cost allocation methodology would be indirectly applied to the additional capacity to meet the reliability need of ~~30~~13% of grandfathered design day. Prior to the allocation of capacity costs to the rate classes through the CGA model, and for the purpose of modeling the utilization of resources to meet firm requirements, the Company's dispatch model would reflect that a portion of the capacity resources needed to meet this requirement were not available to meet firm demand. The specific costs of these resources "set aside" for this reliability requirement would be included in the CGA model, while the CECRC revenues would be credited to system capacity costs before the resulting net capacity costs are allocated to the rate classes, just as capacity assignment and capacity release revenues are credited in the CGA calculation. Thus, the CGA cost allocation methodology would be employed to allocate the CECRC revenues to the rate classes to derive the class unit demand charges.

The CGA cost allocation methodology produces the unit demand charge to the high load factor and low load factor classes that is consistent with the assignment of capacity and associated costs charged to non-grandfathered customers. On the other hand, the capacity requirements for ~~30~~13% of grandfathered design day load, would not be assigned to suppliers, but rather would be reflected in the Company's overall portfolio planning.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
SECOND SET OF INFORMATION REQUESTS FROM THE ATTORNEY GENERAL
D.T.E. 06-36

Date: July 21, 2006
Amended: October 6, 2006

Responsible: Joseph A. Ferro, Manager Regulatory Policy

AG 2-3: State the reason(s) for the Company's omission of a cost allocation methodology from its proposal to address the risk of grandfathered overtakes.

RESPONSE: As discussed in responses to Amended AG 2-1 and Amended AG 2-2, the basis for the Company's cost allocation methodology was using the MDQ associated with ~~30~~13% of grandfathered design day load to derive the capacity costs assigned to the grandfathered customers. In addition to this volumetric allocator, or billing determinant, the unit cost assigned was the average cost of system capacity because of the nature of how this reliability requirement fits into and is part of the Company's overall integrated resource planning as stated in responses to SPR 1-12 and SPR 1-14, as well as, in Hess 1-6 and Hess 1-18. More specifically, because the availability of the capacity associated with the risk of grandfathered overtakes is determined through its continuous and long-term portfolio planning through its Forecast and Supply Plan, the impact that this risk requirement has on the portfolio, and the associated costs, are subject to continuous change.

Conversely, capacity costs allocated through the Company's Cost of Gas methodology relies on the modeling of dispatched resources to meet firm sales and non-grandfathered demand. The requirement of ~~30~~13% of grandfathered load is not being served, but rather results in the Company needing to have resources available on a Critical Day in the event of system under-deliveries. Therefore, determining another allocation methodology to allocate capacity costs to address the risk of grandfathered overtakes would seem to be somewhat arbitrary and/or subjective as compared to using the system average cost of capacity.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
SECOND SET OF INFORMATION REQUESTS FROM THE ATTORNEY GENERAL
D.T.E. 06-36

Date: July 21, 2006
Amended: October 6, 2006

Responsible: Joseph A. Ferro, Manager Regulatory Policy

AG 2-8: Please refer to the response to Exh. AG-1-10. Provide all CECRC calculations based on actual 2005/06 peak CGA costs and include all supporting workpapers, calculations, and assumptions.

RESPONSE: Please see Amended Attachment AG-2-8-1 for the CECRC calculated rate using the system average unit capacity cost based on actual capacity costs for the months of November 2005 through June 2006, and July 2006 through October 2006 capacity costs at the latest June 2006 capacity rates. Note that, because the CECRC is based on annual capacity costs, the Company interpreted that the question is requesting to use actual capacity costs from the beginning of the 2005/06 peak period through October 2006. Also note that, since most capacity rates are the same from month-to-month, the June 2006 through October 2006 capacity costs should be quite similar to the ultimate actuals.

See Attachment AG-2-8-2 for the detail of the annual capacity costs based on the monthly actuals. Also see response to Amended SPR-1-11 for the support of all other data – (a) grandfathered Design day, (b) total system design day, (c) Capacity Release / Off-system Sales revenues, and (d) annual grandfathered throughput.

Attachment AG 2-8
Amended 10-06-06

Capacity Exempt Customer Reliability Charge
Example Calculation

Row	Description		Amount			Calculation
(1)	Capacity Exempt Customer Peak Day		57,674	Dth		Revised 10-06
(2)	Daily Metered Cap Exempt Peak Day		24,800			43% x (1)
(3)	Reliability Factor per D-M Cap Exempt		30%			
(4)	Reliability Capacity		7,440	Dth		(2) x (3)
(5)	Reliability Factor per Cap Exempt Peak Day				13%	(4) / (1)
(6)	**Actual** Annual Unit Capacity Cost	$	**130.97**	per Dth		
(7)	Reliability Costs	$	974,410			(1) x (2) x (3)
(8)	Capacity Release / OSS Margin Revenues	$	(6,407,187)			
(9)	Total System Design Day		504,151	Dth		
(10)	Capacity Release / OSS Credit	$	(94,553)			(8) x ((4) / (9)
(11)	Prior Period Under / (Over) Recovery	$	-			
(12)	Total CECRC Allowable Costs for Period	$	879,856			(4) + (7) + (8)
(13)	Capacity Exempt Customer Throughput (Therms)		86,722,280			
(14)	CECRC Charge per therm	$	**0.0101**			(9) / (10)

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
SECOND SET OF INFORMATION REQUESTS FROM THE ATTORNEY GENERAL
D.T.E. 06-36

Date: July 21, 2006
Amended: October 6, 2006

Responsible: Joseph A. Ferro, Manager Regulatory Policy

AG 2-10: Please refer to the response to Exh. AG-1-19. Please provide a complete, detailed, and accurate explanation of the phrase "all its requirements."

RESPONSE: The categories of "all its requirements" referenced in response to AG-1-19 was listed in a parenthetical as "firm sales, non-grandfathered and capacity associated [with] reliability needs in connection with grandfathered load". All of the Company's requirements entail its obligation to provide reliable service to all its firm customers. To meet this obligation, the Company needs available resources every day of the year, particularly on design day. Thus, the Company needs to have: (1) adequate capacity and supply to satisfy firm sales design day load, (2) capacity to assign to suppliers on behalf of non-grandfathered customers to meet their design day load, and (3) to ensure that those resources are solely used to meet firm sales and non-grandfathered customers' design day load, and thus are sufficient, on a Critical Day, a certain level of additional resources available in the event that the Company experiences under-deliveries on its system due to the grandfathered load on the system. The Company has assessed that ~~30~~13% of grandfathered design day load reasonably addresses system reliability.

Northern Utilities, Inc.
DG 06-098
Attachment Staff 3-16 (c)

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
THIRD SET OF INFORMATION REQUESTS FROM THE ATTORNEY GENERAL
D.T.E. 06-36

Date: August 31, 2006
Amended: October 6, 2006

Responsible: Francisco C. DaFonte, Director, Energy Supply Services

AG 3-7: Please state whether Bay State intends for its resource manager to manager the 13~~0~~% capacity reserve that it would acquire if the Department approves its proposal put forth in this docket.

RESPONSE: Bay State will determine the best-cost approach to managing the 13~~0~~% reserve in a similar fashion as that described in its response to AG 3-01. That is, the Company feels that an RFP process is the best way to derive the best value for the management of any resource. Moreover, depending on whether the resource is on-system in the form of LNG and/or propane or upstream, will have a direct impact on Bay State's decision to outsource the management of the 13~~0~~% reserve since the Company does not currently outsource the management of any on-system assets.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
FIRST SET OF INFORMATION REQUESTS FROM SPRAGUE ENERGY, INC.
D.T.E. 06-36

Date: July 10, 2006
Amended: October 6, 2006

Responsible: Joseph A. Ferro, Manager Regulatory Policy

SPR 1-2: Please refer to Exhibit BSG-1, Attachment JAF-2. Please explain whether Mr. Ferro was able to identify and isolate the under-deliveries related to grandfathered firm transportation customers as opposed to those related to other customers.

RESPONSE: Exhibit BSG-1, Attachment JAF-2, presents the twenty highest daily overtakes of Daily Metered pools, net of over-delivered quantities of other Daily Metered pools. Since the Company allows suppliers to aggregate all of their grandfathered and non-grandfathered customers in one Daily Metered pool, and similarly all Non-daily Metered customers in another pool, the Company is not able to identify and isolate the under-deliveries (or overtakes) of grandfathered customers from non-grandfathered customers. Note that the Company believes that analyzing the Daily Metered pools ~~provides a reasonable~~ represents ~~ation of~~ grandfathered overtakes of 43% of all grandfathered customers, which can be used to determine an incremental planning standard relative to all grandfathered design day load. ~~because Daily Metered grandfathered load represents approximately 90% of all of the load of Daily Metered customers/pools.~~

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
FIRST SET OF INFORMATION REQUESTS FROM SPRAGUE ENERGY, INC.
D.T.E. 06-36

Date: July 14, 2006
Amended: October 6, 2006

Responsible: Joseph A. Ferro, Manager Regulatory Policy

SPR 1-11: Please refer to Exhibit BSG-1, Attachment JAF-3. Please provide all analyses, source documents and workpapers relied upon by Mr. Ferro in the preparation of the referenced attachment.

RESPONSE: Please see Attachment SPR 1-11, which consists of x pages that include the following data used to prepare Amended Attachment JAF-3, and Supplemental Hess 1-16 – Revised for the Capacity Exempt Peak Day:

- Capacity exempt Customer Peak Day of ~~58,846~~57,674 Dth – ~~Page 1~~Supplemental Hess 1-16 - Revised
- Bay State's total system design day of 504,151 Dth – Page 1
- Annual capacity costs of $60,400,925 used to derive annual unit capacity cost of $131.91 / Dth – Page 2
- Associated MDQ of 458,243 Dth used to derive the annual unit capacity cost of $131.91 / Dth – Page 3
- Twelve months, March 2005 through February 2006 of actual capacity release revenues of $6,407,187 – Page 4
- Annual throughput (forecast demand) of all capacity exempt customers of 86,722,280 therms for the period of November 2005 through October 2006 – Page 5

Northern Utilities, Inc.
DG 06-098
Attachment Staff 3-16 (c)

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
FIRST SET OF INFORMATION REQUESTS FROM SPRAGUE ENERGY, INC.
D.T.E. 06-36

Date: July 10, 2006
Amended: October 6, 2006

Responsible: Joseph A. Ferro, Manager Regulatory Policy

SPR 1-13: Please refer to Exhibit BSG-1, Attachment JAF-3. Is Bay State proposing that any additional capacity acquired pursuant to its proposal in this docket would be added to its overall system portfolio and that grandfathered transportation customers will pay the same average annual unit capacity cost for the 13~~0~~% reserve margin that sales service customers pay through Bay State's cost of gas adjustment clause and non-grandfathered transportation customers pay via their assignment of capacity? If so, please explain what reconciliation process will exist to true up the rates paid by grandfathered customers against the actual capacity costs, net of capacity release and off system sales, realized by Bay State. If not, please explain how Bay State proposes to segregate costs and capacity release and off system sales revenues.

RESPONSE: Bay State is proposing that going forward for every year, whether the Company needs to acquire additional capacity for growth, replacing resources in connection with contracts that are expiring, or to satisfy system reliability associated with capacity exempt load on its system, that grandfathered customers be charged the same average annual unit capacity cost for the ~~30~~13% reserve margin that sales service customers pay through Bay State's cost of gas adjustment clause and non-grandfathered transportation customers pay via their assignment of capacity. Bay State is proposing to reconcile the capacity costs associated with ~~30~~13% of grandfathered design day load with recoveries associated with the application of the Capacity Exempt Customer Reliability Charge ("CECRC") by matching the calculated capacity costs based on the then-current design day load, capacity costs and 12-months capacity release / OSS margin revenues with actual CECRC collections. Thus, capacity costs associated with this reliability requirement will be considered actual costs based on the assessment of grandfathered design day load and system capacity costs prior to entering into the Peak Period beginning November 1. Please also see response to Amended AG 1-18.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
FIRST SET OF INFORMATION REQUESTS FROM SPRAGUE ENERGY, INC.
D.T.E. 06-36

Date: July 14, 2006
Amended: October 6, 2006

Responsible: Joseph A. Ferro, Manager Regulatory Policy

SPR 1-15: Please refer to (Amended) Exhibit BSG-1, Attachment JAF-3. Please provide a comparable analysis assuming that the additional capacity acquired by Bay State costs the same as the most expensive long-term capacity currently held in Bay State's portfolio.

RESPONSE: Please see Amended Attachment SPR 1-15.

The most expensive long-term capacity currently held in Bay State's portfolio, and reflected in the attached calculation, is the annual capacity on the Portland Natural Gas Transmission System (PNGTS) under its FT rate schedule. Note that the MDQ of this capacity is 4,900 Dth, and the term of the associated contract expires on March 10, 2019.

Attachment SPR 1-15
Amended 10-06-06

Capacity Exempt Customer Reliability Charge
Example Calculation

Row	Description		Amount		Calculation
(1)	Capacity Exempt Customer Peak Day		57,674	Dth	Revised 10-06
(2)	Daily Metered Cap Exempt Peak Day		24,800		43% x (1)
(3)	Reliability Factor per D-M Cap Exempt		30%		
(4)	Reliability Capacity		7,440	Dth	(2) x (3)
(5)	Reliability Factor per Cap Exempt Peak Day			13%	(4) / (1)
(6)	**Highest** Annual Unit Capacity Cost	$	**310.25**	per Dth	
(7)	Reliability Costs	$	2,308,243		(1) x (2) x (3)
(8)	Capacity Release / OSS Margin Revenues	$	(6,407,187)		
(9)	Total System Design Day		504,151	Dth	
(10)	Capacity Release / OSS Credit	$	(94,553)		(8) x ((4) / (9)
(11)	Prior Period Under / (Over) Recovery	$			
(12)	Total CECRC Allowable Costs for Period	$	2,213,690		(4) + (7) + (8)
(13)	Capacity Exempt Customer Throughput (Therms)		86,722,280		
(14)	CECRC Charge per therm	$	**0.0255**		(9) / (10)

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
FIRST SET OF INFORMATION REQUESTS FROM HESS CORPORATION
D.T.E. 06-36

Date: July 14, 2006
Amended: October 6, 2006

Responsible: Joseph A. Ferro, Manager Regulatory Policy

Hess 1-15: Are grandfathered customers in the non-daily metered program part of Bay State's 13~~0~~ percent reserve proposal?

RESPONSE: The Company's proposal includes a reliability requirement, or incremental planning standard, associated with 13~~0~~ percent of the design day load of all grandfathered customers, those customers whose requirements are not met with the Company's firm capacity resources.

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DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
FIRST SET OF INFORMATION REQUESTS FROM HESS CORPORATION
D.T.E. 06-36

Date: July 14, 2006
Amended: October 6, 2006

Responsible: Francisco C. DaFonte, Director, Energy Supply Services

Hess 1-23: Describe Bay State's proposal for the disposition of revenues received from mitigation efforts for the 13~~0~~ percent reserve capacity. How can Bay State distinguish between mitigation efforts for the 13~~0~~ percent reserve capacity and other capacity? Which capacity has priority for mitigation and why? How will Bay State determine which mitigation revenues relate to the 13~~0~~ percent reserve and which relate to other capacity?

RESPONSE: In order to maximize capacity mitigation revenues associated with the 13~~0~~ percent reserve, Bay State would manage the capacity associated with the incremental planning standard and all other capacity on an integrated basis so that it can take advantage of the increased marketability of higher volume capacity paths. If Bay State were to try to mitigate the 13~~0~~ percent capacity associated with the incremental planning standard separately, it would result in much smaller volume capacity paths that are less desirable and more difficult to market.

As for the allocation of capacity release revenues, Bay State would simply take the ratio of total design day capacity to the capacity associated with the incremental planning standard (13~~0~~% of grandfathered design day) and allocate revenues on that same basis. For example, if the ratio of design day capacity to planning standard capacity is 90/10 then $1 million in capacity release revenues would be allocated $900,000 to system design day capacity less the reserve and $100,000 to the reserve representing 13~~0~~% GF design day load. Note that such an assignment calculation of capacity release revenues is shown on Amended Attachment JAF-3, at line (~~7~~10).

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
SECOND SET OF INFORMATION REQUESTS FROM HESS CORPORATION
D.T.E. 06-36

Date: August 17, 2006
Amended: October 6, 2006

Responsible: Francisco C. DaFonte, Director, Energy Supply Services

HESS 2-4: How does Bay State intend to represent the 13~~0~~% reserve in its supply planning forecast? As a 365 day need? A 151 day need? A 10 day need? Or only a design day need?

RESPONSE: Bay State will first establish a design day need that incorporates the proposed 13~~0~~% reserve. Bay State will then run its SENDOUT® simulation and optimization model under design winter conditions to test various resource alternatives to ensure that there is no supply shortfall. During this process SENDOUT® establishes optimal design day and seasonal contract quantities for the selected resource(s). The seasonal contract quantity need will depend largely on the load profile of the grandfathered customers but should most likely be no more than 30 days.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
SECOND SET OF INFORMATION REQUESTS FROM HESS CORPORATION
D.T.E. 06-36

Date: August 17, 2006
Amended: October 6, 2006

Responsible: Joseph A. Ferro, Manager Regulatory Policy

HESS 2-6: Has Bay State performed a comparative cost analysis between installing flow control meters on the grandfathered customers and a range of costs for the 13~~0~~ percent reserve? If so, please provide such analysis.

RESPONSE: The anticipated cost of the incremental planning standard is presented at page 14 of Mr. Ferro's Direct Testimony. The anticipated cost of installing flow-control metering is presented at pages 5-6 of Mr. Ferro's Direct Testimony and is greater than the cost of the incremental planning standard. As described on page 6 of this testimony, the approximate capital cost per customer of installing flow-control metering of $20,000 yields an annual cost of $3,134 for approximately 1,750 grandfathered customers, or $5.5 million of annual costs or revenue requirement. This $5.5 million compares to the total CECRC annual costs provided on Amended Attachment JAF-3 of approximately $1 million. ~~and stated on page 14 of $2.3 million.~~

Further, Mr. Ferro cited the benefits of the proposed incremental planning standard, which include: (i) the ability for customers and their suppliers to continue to realize the economic benefits of their capacity exemption, (ii) lower costs compared to the installation of flow-control metering, (iii) elimination of shut-off risks for grandfathered customers, and (iv) ease of the transition for customers that desire to return to sales service.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
SECOND SET OF INFORMATION REQUESTS FROM HESS CORPORATION
D.T.E. 06-36

Date: August 17, 2006
Amended: October 6, 2006

Responsible: Francisco C. DaFonte, Director, Energy Supply Services

HESS 2-8: Regarding Hess 1-26, when does Bay State anticipate the need for additional capacity in the Springfield and Lawrence divisions if a 13~~0~~% reserve is approved?

RESPONSE: The Company is assuming the question refers to Hess 1-2.

Given a 1% growth assumption used in its most recently approved load forecast and supply plan (DTE 02-75), Bay State anticipates ~~a~~no capacity deficiency of ~~approximately 1,928 MMBtu~~ will exist in the Springfield/Lawrence division ~~in~~through the year 200~~8~~9-2010~~9~~ if a 13~~0~~% reserve is approved.

COMMONWEALTH OF MASSACHUSETTS
DEPARTMENT OF TELECOMMUNICATIONS AND ENERGY

RESPONSE OF BAY STATE GAS COMPANY TO THE
FIRST SET OF INFORMATION REQUESTS FROM HESS CORPORATION
D.T.E. 06-36

Date: September 12, 2006
Supplemental: October 6, 2006

Responsible: Joseph A. Ferro, Manager Regulatory Policy

Hess 1-16: Please indicate by rate class, the MDQ and number of customers for the following categories as of December 2005, or some other more recent date if available and please identify that date:

a. Grandfathered customers in the daily metered program.
b. Grandfathered customers in the non-daily metered program.
c. Non-grandfathered customers in the daily metered program.
d. Non-grandfathered customers in the non-daily metered program.

RESPONSE: The Company has further reviewed its derivation of the MDQ and number of customers, by Daily Metered and Non-daily Metered pools, by grandfathered and non-grandfathered, and by rate class and, as a result of inadvertent inaccuracies, wishes to revise such MDQs and number of customers. Therefore, please see Attachment Hess-1-16 – Revised for the requested information as of June 2006.

The MDQs of each account are calculated using each account's daily base load and use per degree day applied to design day effective degree days (EDD). Such estimating factors are those in the billing system at the time of the calculation. This calculation should have generated MDQs for all accounts that were no lower than the billing system's minimum use for each account. The previous calculation inadvertently did not incorporate this subroutine. Thus, the MDQs were revised to reflect such minimum use to accounts where the calculation produced a MDQ lower than the minimum use. Also, the previous calculation used a design day 78 EDD, which was intended to be the average of the Company's three service territories' design EDD. The correct average of 79 EDD was used for the revised calculations.

SUPPLEMENTAL
RESPONSE: Supplemental Attachment Hess 1-16 – Revised presents at the bottom of the schedule the following 2 categories of the totals of design day use and number of customers of all rate classes:

(1) Grandfathered – (a) Daily Metered and (b) Non-daily Metered
(2) Daily Metered - (a) Grandfathered and (b) Non-grandfathered

In reviewing this customer data, the Company realized that only 43%, or 24,590 Dth, of the grandfathered load is currently in daily metered pools. Also, the Company decided to use this data, run as of June 15, 2006, to update its total grandfathered (or capacity exempt) design day from 58,846 Dth to 57,674 Dth.

Note that the Company's original proposal was based on information that most (90%) of the daily metered pools requirements was comprised of grandfathered load. This information was apparently based on including special contract load in the daily metered pools, as approximately 90% of the daily metered pools requirements, including special contracts, are grandfathered. However, the Company's proposal for an incremental planning standard is not in connection with any special contract load.

Bay State Gas Company
Transportation Customers as of June15, 2006 - Number of Customers and MDQ

	T01	T03	T40	T41	T42	T43	T50	T51	T52	T53
Daily Metered										
Grandfathered DM Count	NA	NA	7	13	15	11		4	24	53
Grandfathered DM MDQ (DTH)	NA	NA	16	399	2,159	2,713	-	43	2,114	17,146
Non-Grandfathered DM Count	NA	NA	0	1	7	3	0	0	1	11
Non-Grandfathered DM MDQ (DTH)	NA	NA	-	5	927	3,089	-	-	13	2,822
Non-Daily Metered										
Grandfathered Non-DM Count	0	5	325	595	204	NA	136	193	88	0
Grandfathered Non-DM MDQ (DTH)	0	7	984	9,410	14,264	NA	133	3,286	5,001	NA
Non-Grandfathered Non-DM Count	6	105	572	549	122	NA	249	403	67	0
Non-Grandfathered Non-DM MDQ (DTH)	1	161	1,616	8,602	8,599	NA	298	3,374	2,933	NA

GF	Design Day		# Custs		DM			# Custs	
DM	24,590	43%	127	8%	GF	24,590	78%	127	85%
Non-DM	33,084	57%	1,546	92%	Non-GF	6,857	22%	23	15%
TOTAL	57,674		1,673			31,447		150	

NiSource
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January 23, 2007

VIA OVERNIGHT DELIVERY AND ELECTRONIC FILING

Mary L. Cottrell, Secretary
Department of Telecommunications and Energy
One South Station
Boston, MA 02110

Re: Bay State Gas Company, D.T.E. 06-36

Dear Ms. Cottrell:

Enclosed for filing, on behalf of Bay State Gas Company ("Bay State"), is Bay State's re-filing of its proposed tariffs, M.D.T.E. No. 35 (Index Page, Section 2, Section 13 and Appendix C) and M.D.T.E. No. 36, with the revised Effective Date of July 1, 2007, in order to accommodate the current procedural schedule for this docket. Today's filing reflects the amendments made by Bay State in its October 6, 2006 Amended Filing ("October 6th Amended Filing") and also includes the updates to Section 13 which were requested by Staff during the December 20, 2006 Hearing in this matter and reflected in Bay State's response to RR-DTE-10. The instant filing is intended to replace all previously filed versions of M.D.T.E. No. 35 (Index Page, Section 2, Section 13 and Appendix C) and M.D.T.E. No. 36 filed in this docket.

By way of background, Bay State filed with the Department of Telecommunications and Energy ("Department"), its System Protection Plan for Grandfathered Overtakes on March 31, 2006 ("March 31, 2006 Filing"), as required by the Department's Order in D.T.E. 05-27. The March 31, 2006 Filing included proposed revisions to Bay State's tariffs M.D.T.E. No. 35 (Index Page, Section 2, Section 13 and Appendix C) and M.D.T.E. No. 36 with a proposed Effective Date of September 1, 2006. Subsequently, on June 15, 2006 and then again on September 26, 2006, Bay State re-filed its proposed M.D.T.E. No. 35 (Index Page, Section 2, Section 13 and Appendix C) and M.D.T.E. No. 36, with the sole change of a revised Effective Date of December 1, 2006 and February 1, 2007, respectively, in order to accommodate the procedural schedule established for this docket. On October 6, 2006, Bay State amended its filing as a result of the data clarification and revised planning standard identified by Bay State on October 2, 2006. The October 6th Amended Filing included revisions to M.D.T.E. No. 35 - Section 13, at page 13-13 and Appendix C and to M.D.T.E. No. 36, page 2 of 21. The October 6th Amended Filing tariff pages had the Effective Date of February 1, 2007. The instant filing revises the Effective Date to July 1, 2007.

Please do not hesitate to contact me at (508) 836-7394 or Robert L. Dewees, Jr., of Nixon Peabody LLP, at (617) 345-1316 with any questions concerning this filing.

Very truly yours,

Patricia M. French

cc: Julie Howley Westwater, Esq., Hearing Officer, DTE
Kevin Brannelly, Director, Rates and Revenue Requirements, DTE
George Yiankos, Director, Gas Division, DTE
Jamie M. Tosches, Esq., Office of the Attorney General

DISTRIBUTION AND DEFAULT SERVICE TERMS AND CONDITIONS

Section

DISTRIBUTION AND DEFAULT SERVICE TERMS AND CONDITIONS

2.0 **DEFINITIONS**

Adjusted Target Volume ATV	The volume of Gas determined pursuant to Section 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.
Authorization 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.

DISTRIBUTION AND DEFAULT SERVICE
TERMS AND CONDITIONS

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.
Capacity Exempt Customer	Any Customer receiving Distribution Service whose TCQ is equal to zero as provided for in either Section 13.3.3 or Section 13.3.5 of these Terms and Conditions.
City Gate	The interconnection between a Delivering Pipeline and the Company's distribution facilities.
Company	Bay State Gas Company
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 19.0 of these Terms and Conditions, a Day declared at any time by the Company in its reasonable discretion when unusual operating

DISTRIBUTION AND DEFAULT SERVICE TERMS AND CONDITIONS

	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 MDTE approves a suitable replacement.
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.
Default Service	Gas commodity service provided to a Customer who is not receiving Supplier Service, in accordance with Section 15.0 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.
Dekatherm	Ten Therms.

DISTRIBUTION AND DEFAULT SERVICE
TERMS AND CONDITIONS

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.
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 25.0 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.
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.

DISTRIBUTION AND DEFAULT SERVICE TERMS AND CONDITIONS

Gas Service Area	An area within the Company's distribution system as defined in Section 4.0 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.
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 17.0 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 Suppliers' Peaking Service Account pursuant to Section 16.0 of these Terms and Conditions shall be equal to the sum of the Customers' MDPQs in a Supplier's Aggregation Pool.
MDTE	The Massachusetts Department of Telecommunications and Energy.
Month	A calendar month of Gas Days.
Monthly Index	The average of the Daily Indices for the relevant Month.

DISTRIBUTION AND DEFAULT SERVICE
TERMS AND CONDITIONS

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, and other such non-confidential information as may be reasonably required by the Company.
Off-Peak Season	The consecutive months May to October, inclusive.
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 19.0 of these Terms and Conditions.
Peak Day	The forecasted Gas Day during which the Company's system experiences the highest aggregate Gas Usage as approved by the MDTE.
Peaking Capacity	Capacity normally used by the Company to provide Peaking Service.
Peak Season	The consecutive months November to April, inclusive.
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 maximum balance in the account shall equal the Peaking Supply assigned to the Supplier pursuant to these Terms and Conditions.

DISTRIBUTION AND DEFAULT SERVICE
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 post the Peaking Service Rule Curve on its Website as identified in Section 23.0 of these Terms and Conditions
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.
Pre-Determined Allocation	Instructions from the Supplier to the Company for the allocation of discrepancies in confirmed nominations among the Supplier's Aggregation Pools and/or Customers as set forth in the Supplier's Service Agreement.
Reference Period	A period of at least twelve (12) months for which a Customer's Gas Usage information is typically available to the Company.

DISTRIBUTION AND DEFAULT SERVICE TERMS AND CONDITIONS

Supplier	Any entity licensed by the MDTE 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	Contracts for capacity in off-system storage Capacity facilities used to accumulate and maintain gas inventories for redelivery to the Company's city gates.
Underground Storage Withdrawal Capacity	Capacity for the withdrawal of gas inventories 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.

DISTRIBUTION AND DEFAULT SERVICE
TERMS AND CONDITIONS

13.0 CAPACITY ASSIGNMENT

13.1 Applicability

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

13.2 Identification of Capacity for Assignment

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

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

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

13.3 Determination of Pro-Rata Shares of Capacity

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

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

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

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

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

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

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

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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 16.0 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, subject to the provisions of Section 13.4.2, be equal to the cumulative sum of the pro-rata shares of Pipeline Capacity, Underground Storage Withdrawal Capacity and Peaking Capacity for all Customers enrolled in said Aggregation Pool as of five (5) Business Days prior to the Assignment Date.

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

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

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

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

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

13.5 <u>Release of Contracts</u>

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

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

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

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

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

13.6 Annual Reassignment of Capacity

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

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

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

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13.7 <u>Recall of Capacity</u>

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

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

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

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

(2) The Supplier returning said Customers to the Company's Default Service certifies that it will no longer offer service to a particular market sector, <u>i.e.</u>, 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

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

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

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

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

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

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

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

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

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

13.8 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.

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

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

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

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

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13.9 Company-Managed Supplies

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

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

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

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

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

13.10 Open-Season Capacity Assignments

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

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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 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.

13.12 Capacity Exempt Customer Reliability Charge

13.12.1 The Company requires access to firm upstream pipeline, storage and peaking capacity as well as on-system peak-shaving resources to maintain the reliability of its distribution system operations. The Capacity Exempt Customer Reliability Charge (CECRC) allows the Company to recover the costs of such resources required in proportion to the level of Capacity Exempt Customer loads on its system.

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13.12.2 Each year, the Company shall calculate a CECRC rate per therm applicable to all Capacity Exempt Customer throughput for the annual period beginning November 1. The CECRC rate per therm and the associated derivation shall be set forth in Appendix C to these Terms and Conditions.

13.12.3 The CECRC rate per therm shall be calculated as follows:

(1) Allowable CECRC costs shall equal the sum of the following;

(a) The product of the total Capacity Exempt Customer ***Daily-Metered Service*** peak day requirements, determined prior to November 1, the system average annual unit capacity cost, and a factor of 30% (thirty percent).

(b) A capacity release and off-system sales revenue credit equal to the total projected annual capacity release and off-system sales margin revenues for the annual period beginning November 1 multiplied by the ratio of ***30% of*** the total Capacity Exempt Customer ***Daily-Metered Service*** peak day requirements to the total system peak day requirements.

(c) Any difference, positive or negative, between the costs of the CECRC as established for the previous annual period November 1 through October 31 and the actual collections from the application of the CECRC rate to Capacity Exempt Customer throughput for the corresponding period.

13.12.4 The total revenues recovered pursuant to the CECRC shall be credited to the Company's CGA costs in accordance with M.D.T.E. No. 36.

13.13 <u>Monitoring Capacity Exempt Customer Overtakes</u>

13.13.1 Overtakes associated with Capacity Exempt Customer loads threaten the reliability of Bay State's distribution system. Therefore, the Company shall monitor Supplier overtakes associated with Capacity Exempt Customer loads on Critical Days.

13.13.2 All Capacity Exempt Customers served by a Supplier that experiences an overtake after the trading of imbalances on a Critical Day that exceeds thirty percent (30%) of the aggregate Gas Usage of Capacity Exempt Customers within its Aggregation Pool shall lose their status as exempt from the mandatory capacity assignment provisions of these Terms and Conditions. The only exception to losing such status shall be that any daily-metered customer whose Gas Usage is zero on the critical day when the overtake of such

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Aggregation Pool exceeds thirty percent (30%) shall not lose its capacity assignment exemption.

In order to determine whether a Supplier has exceeded the allowed 30% overtake for Capacity Exempt Customer loads, the Company shall perform the following calculations applicable to Daily-Metered and Non-Daily Metered Aggregation Pools for each day that the Company declares a Critical Day and provides notice thereof to Suppliers pursuant to Section 19.0 of these Terms and Conditions.

(1) For Daily Metered Pools, the Company shall determine the receipts applicable to Capacity Exempt Customer loads by subtracting the total metered Gas Usage for all non-Capacity Exempt Customers in the Aggregation Pool divided by a factor of one hundred and two percent (102%) from the total deliveries for the Aggregation Pool. The total Gas Usage for all Capacity Exempt Customers in the Aggregation Pool shall be subtracted from the receipts for Capacity Exempt Customers calculated pursuant to this provision to determine the overtake applicable to Capacity Exempt Customers, if any. The percentage overtake shall be determined by dividing the Capacity Exempt Customer overtake into the total Gas Usage for all Capacity Exempt Customers in the Aggregation Pool.

(2) For Non-Daily Metered Pools, the Company shall calculate the percentage overtake for the Aggregation Pool by subtracting the ATV from the actual receipts from the Supplier. The percentage overtake for the Aggregation Pool shall be determined by dividing the overtake for the Aggregation Pool by the ATV. The percentage overtake for Capacity Exempt Customers in the Non-Daily Metered Aggregation Pool shall equal the percentage overtake for the total Aggregation Pool.

(3) The calculation of Capacity Exempt Customer overtakes shall take into consideration trading of daily imbalances by Suppliers as permitted under Section 24.7.

13.13.3 Each Supplier serving Capacity Exempt Customers that forego their capacity assignment exemption, in accordance with Section 13.13.2, shall be assigned capacity pursuant to these Terms and Conditions on the next allowable assignment date.

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APPENDIX C

Capacity Exempt Customer Reliability Charge

Row	Description	Amount	Calculation
(1)	Daily-Metered Capacity Exempt Customer Peak Day	XX Dth	
(2)	Factor	30%	
(3)	Reliability Capacity		(1) x (2)
(4)	Average Annual Unit Capacity Costs	$__ per Dth	
(5)	Reliability Costs		(3) x (4)
(6)	Capacity Release / OSS Margin Revenues	$___	
(7)	Total System Design Day	XX Dth	
(8)	Capacity Release / OSS Credit		(6) x ((3)/(7))
(9)	Prior Period Under / (Over) Recovery	$___	
(10)	Total CECRC Allowable Costs for Period	$____	(5) + (8) + (9)
(11)	Capacity Exempt Customer Throughput	Dth	
(12)	CECRC Charge per therm	$____	(10) / (11)

COST OF GAS ADJUSTMENT CLAUSE

Section

1.0 Purpose

The purpose of this clause is to establish procedures that allow Bay State Gas Company ("Bay State" or the "Company"), subject to the jurisdiction of the Department of Telecommunications and Energy ("Department") to adjust, on a semiannual basis, its rates for firm gas sales service in order to recover the costs of gas supplies, along with any taxes applicable to those supplies, pipeline and storage capacity, production capacity and storage, bad debt expense associated with purchase gas costs, and the costs of purchased gas working capital, to reflect the seasonal variation in the cost of gas, and to credit all supplier refunds and the margins above the Annual Threshold associated with capacity credits from non-core sales and transportation, interruptible sales and transportation and capacity release sales, as well as revenues from the billing of the Capacity Exempt Customer Reliability Charge, to firm ratepayers.

2.0 Applicability

This Cost of Gas Adjustment Clause ("CGAC") shall be applicable to Bay State and all firm gas sales made by Bay State, unless otherwise designated. The application to the clause may, for good cause shown, be modified by the Department. See Section 13.0, "Other Rules."

COST OF GAS ADJUSTMENT CLAUSE

3.0 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, other gas supply expense incurred to procure and transport supplies and bad debt percent (from the last general rate case) applied to allowable CGAC costs for the forecast period, 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 filings outlined in Section 12.0.

4.0 Effective Date of Gas Adjustment Factor

The date on which the seasonal Gas Adjustment Factors ("GAF") become effective shall be the first day of the first month of each season as designated by the Company. Unless otherwise notified by the Department, the Company shall submit GAF filings as outlined in Section 12.0 of this clause at least 45 days before they are to take effect.

5.0 Definitions

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

(1) **Annual Threshhold** - A threshold level of margins, established annually and separately for Capacity Release, Interruptible Sales and Off-System Sales, based on the twelve months ended April 30 each year, the level above which the Company retains 25% of such margins.

(2) **Bad Debt Expense** - is the uncollectable expense attributed to the Company's gas costs plus allowable working capital derived from the gas cost portion of bad debt.

(3) **Base Load Requirements** - The annual quantity of gas supply needed to satisfy the lowest level of firm demand based on the average July and August loads.

(4) **Capacity Exempt Customer Reliability Charge ("CECRC") Revenues** – The revenues from billing the CECRC to capacity exempt firm transportation customers for the cost of capacity resources needed for system reliability and based on 13% of the capacity exempt design day requirements.

(5) **Capacity Release Revenues** - The economic benefit derived from the sale of upstream capacity.

(6) **Carrying Charges** - Interest expense calculated on the average monthly balance using the consensus prime rate as reported in the *Wall Street Journal*.

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(7) **Economic Benefit** - The difference between the revenues received and the marginal cost determined to serve non-core customers.

(8) **Interruptible Sales Margins** - The economic benefit derived from the interruptible sale of gas downstream of the Company's distribution system.

(9) **Inventory Finance Charges** - As incurred or billed each month for the carrying costs on the value of the balance of inventory gas for the respective month. The total charges shall represent an accumulation of the projected monthly charges as calculated using the monthly average of financed inventory at the existing (or anticipated) financing rate of the Company or through a trust or other financing vehicle.

(10) **Local Production Capacity and Storage Costs** - Include the ancillary supply costs of providing local manufactured gas, gas dispatching, gas acquisition, and miscellaneous A&G costs as determined in the Company's most recent rate proceeding.

(11) **SMBA** – Simplified Market Based Allocation Method - Used in determining the allocation of gas costs among High and Low Load Factor classes.

(12) **Non-Core Commodity Costs** - The commodity cost of gas assigned to non-core sales to which the GAF is not applied. Non-core sales include sales made under interruptible contracts, non-core contracts and off-system sales.

(13) **Non-Core Sales Margins** – The economic benefit derived from non-core transactions to which the GAF is not applied, including interruptible sales and other non-core sales generated from the use of the Company's Gas Supply resource portfolio.

(14) **Off-System Sales Margin** - The economic benefit derived from the non-firm sales of natural gas supplies upstream of Company's distribution system.

(15) **Number of Days Lag** - The number of days lag to calculate the purchased gas working capital requirement as approved by the Department.

(16) **Off-Peak Commodity** – Unless otherwise approved by the Department, the gas supplies assigned by the Company to serve firm load in the off-peak season.

(17) **Off-Peak Demand** - Unless otherwise approved by the Department, the gas supply demand and transmission capacity assigned by the Company to serve firm load in the off-peak season.

(18) **Off-Peak Period** - May through October.

(19) **Peak Commodity** - Unless otherwise approved by the Department, the gas supplies assigned by the Company to serve firm load in the peak season.

(20) **Peak Demand** - Unless otherwise approved by the Department, gas supply demand, peaking demands, storage and transmission capacity assigned by the Company to service firm load in the peak season.

(21) **Peak Period** - November through April.

(22) **PR Allocator** - The percentage allocated for the portion of annual capacity charges assigned to the seasons calculated in each CGA filing.

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(23) **Pretax Weighted Cost of Capital** - The result of the calculation of the weighted cost of capital minus the weighted cost of debt, divided by one, minus the currently effective combined tax rate, plus the weighted cost of debt.

(24) **Purchased Gas Working Capital** - The allowable working capital derived from peak and off-peak, demand and commodity related costs.

(25) **Tax Rate** is the combined State and Federal income tax rate.

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

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

6.0 Gas Adjustment Factor (GAF) Formula

The Gas Adjustment Factor ("GAF") Formula shall be computed on a semiannual basis using forecasts of seasonal gas costs, carrying charges, sendout volumes, and sales volumes. Forecasts may be based on either historical data or Company projections, but must be weather-normalized. Any projections must be documented in full with each filing.

A separate seasonal GAF will be computed for the combined Low Load Factor classes namely Rates R-3, R-4, G-40, G-41, G-42 and G-43; and for the combined High Load Factor classes namely Rates R-1, R-2, OL, G-50, G-51, G-52 and G-53. The calculation of each seasonal GAF utilizes information periodically established by the DTE. The table below lists the following approved cost factors as approved in D.T.E. 05-27:

Local Production & Storage Cost	\$7,430,587
LNG/LPG Production Cost included above	\$5,045,484
Bad Debt Expense Percentage	2.15%

Peak GAF Formula

The Peak GAF shall be comprised of a peak demand factor (DFp), a peak commodity factor (CFp), a peak production and storage demand factor (PSp), gas suppliers' refund factors (R1 and R2) defined in Section 8.00 and a bad debt factor (BDF) defined in Section 15.00, for the Company's High and Low Load Factor classes and calculated at the beginning of the peak season according to the following formula:

$$GAFp^{x} = DFp^{x} + PSp^{x} + CFp^{x} + BDF - R1 - R2$$

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Peak Demand Factor (DFp) Formula

$$DFp^x = \frac{Dp^x - NCSMp^x - CECRCR}{P : Sales^x} + RFpd + WCFpd$$

and:

$$Dp^x = BASEDp^x + REMAINDp^x + PSp^x$$

and:

$$NCSMp^x = CRR^x + ISM^x + NTSM^x$$

and:

$$RFpd = Rpd/P{:}Sales$$

and:

$$WCFpd = \frac{\dfrac{[(WCApd \times CC) - (WCApd \times CD)] + (WCApd \times CD) + WCRpd}{(1 - TR)}}{P : Sales}$$

and:

$$WCApd = Dp \times (DL/365)$$

Where:

BASEDp	Peak period base use demand charges assigned on the basis of base use entitlements to low cost pipeline supplies using the average of July and August's daily loads.
CC	Weighted cost of capital as defined in Section 500.
CD	Weighted cost of debt as defined in Section 5.00.
CECRCR	Revenues from billing the Capacity Exempt Customer Reliability Charge.
CRR	The returnable Capacity Release Revenues allocated to the peak period. See Section 7.00.
DL	Number of days lag from the purchase of gas from suppliers to the payment by customers.
Dp	Demand Charges allocated to the peak period as defined in Section 5.00.
$NCSMp^X$	The sum of the returnable Interruptible Non-Core Sales Margins, the returnable Capacity Release Revenues and the Off-System margins.

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ISM	The returnable Interruptible Sales Margins allocated to the peak period. See Section 7.00.
NTSM	The returnable Off-System Sales Margins allocated to the peak period. See Section 7.00.
P:Sales	Forecasted sales volumes associated with the peak period.
REMAINDp	Peak period remaining use demand charges assigned to classes on the basis of their load's contribution to the design day load less their base use entitlements to pipeline supplies. This remaining capacity cost is allocated to seasons using the Proportional Responsibility (PR) allocator.
RFpd	Peak demand charge reconciliation adjustment factor per billed peak sales volume associated with demand charges related to the peak period.
Rpd	Reconciliation Costs - Peak demand deferred gas costs, Account 175.21 balance, inclusive of the associated Account 175.21 interest, as outlined in Section 9.00.
TR	Combined Tax Rate as defined in Section 5.00
WCApd	Demand charges allowable for working capital application as defined in Section 10.00.
WCFpd	Working Capital allowable factor per billed peak sales volume associated with demand charges allocated to the peak period as defined in Section 10.00.
WCRpd	Working Capital reconciliation adjustment associated with peak demand charges - Account 176.24 balance as outlined in Section 10.00.
x	Designates Load Factor Specific allocation of costs, based on Simplified Market Based Allocation factors as determined in the Company's most recent rate proceeding.
PSpx	Portion of test year Local Production Capacity and Storage Costs, as defined in Section 5.00, allocated to peak period firm sales through the CGAC as determined in the Company's most recent rate proceeding.

Peak Commodity Factor (CFp) Formula

$$CFp^x = \left[\frac{Cp^x - NCCCp^x + FC^x}{P:Sales^x} \right] + RFpc + WCFpc$$

and:

$$Cp^x = BASECp^x + REMAINCpx$$

and:

$$RFpc = Rpc / P{:}Sales$$

and:

$$WCFpc = \frac{\left[\frac{(WCApc \times CC) - (WCApc \times CD)}{(1 - TR)} \right] + (WCApc \times CD) + WCRpc}{}.$$

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P: Sales

and:

WCApc = Cp x (DL/365)

Where:

BASECp	Peak period base use commodity charges assigned on the basis of base use entitlements to low cost pipeline supplies using the average of July and August daily loads.
CC	Weighted costs of capital as defined in Section 5.00
CD	Weighted costs of debt as defined in Section 5.00.
Cp	Commodity Charges allocated to the peak period as defined in Section 5.00.
DL	Number of days lag from the purchase of gas from suppliers to the payment by customers.
FC	Inventory finance charges as defined in Section 5.00.
NCCCp	Non-Core Commodity Costs allocated to the peak period as defined in Section 5.00.
P:Sales	Forecasted sales volumes associated with the peak period.
REMAINCp	Peak period remaining use commodity charges computed as dispatched commodity costs less base use commodity costs.
RFpc	Peak commodity charge reconciliation adjustment factor per billed peak sales volume associated with commodity charges related to the peak period.
Rpc	Reconciliation Adjustment Costs - Account 175.23 balance, inclusive of the associated Account 175.23 interest, as outlined in Section 9.00.
R	Combined Tax rate as defined in Section 5.00.
WCApc	Commodity charges allowable for working capital application as defined in Section 10.00.
WCFpc	Working Capital allowable factor per peak sales volume associated with commodity charges allocated to the peak period as defined in Section 10.00.
WCRpc	Working Capital reconciliation adjustment associated with peak commodity charges Account 175.24 balance as outlined in Section 10.00.
x	Designates Load Factor class specific allocation of costs, based on Simplified Market Based Allocation factors, as determined in the Company's most recent rate proceeding.

Off-Peak GAF Formula

The Off-Peak GAF shall be comprised of an off-peak demand factor (Dfop) an off-peak production and storage demand factor (PSop), an off-peak commodity factor (Cfop), gas suppliers' refund factors (R1 and R2) defined in Section 8.00 and a bad debt factor (BDF),

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defined in Section 15.00 for the Company's High and Low Load Factor classes, and calculated at the beginning of the off-peak season according to the following formula.

$$GAFop^X = DFop^X + CFop^X + PSop^x + BDF - R1 - R2$$

Off-Peak Demand Factor (DFop) Formula

$$DFop^x = \frac{Dop^x}{OP{:}Sales^x} + RFopd + WCFopd$$

and:

$$Dop^X = Sum{:}BLDop^X + (Sum{:}BLDXop^X \times (1 - PR))$$

and:

$$RFopd = Ropd / OP{:}Sales$$

and:

$$WCFopd = \frac{\frac{[(WCAopd \times CC) - (WCAopd \times CD)]}{(1 - TR)} + (WCAopd \times CD) + WCRopd}{(OP{:}Sales)}$$

and:

$$WCAopd = Dop\ (DL/365)$$

Where:

BLDop	Demand charges billed to the Company during the off peak period for the portion of base demand associated with serving base load requirements as defined in Section 5.00.
BLDXop	Base demand costs in excess of demand costs associated with base load level billed to the Company during the off-peak period.
CC	Weighted cost of capital as defined in Section 5.00.
CD	Weighted cost of debt as defined in Section 5.00
DL	Number of days lag from the purchase of gas from suppliers to the payment by customers.

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Dop	Demand charges allocated to the off-peak period as defined in Section 5.00.
OP:Sales	Forecasted sales volumes associated with the off-peak period.
PR	Proportional Responsibility Allocator - A percentage representing a portion of capacity/product charges incurred in the off-peak season and assigned to the peak period calculated in each CGA filing as defined in Section 5.0.
RFopd	Off-peak demand charge reconciliation adjustment factor per billed off peak throughput volume associated with demand charges related to the off peak period.
Ropd	Reconciliation Costs - Account 175.11 balance, inclusive of the associated Account 175.11 interest, as outlined in Section 9.00.
SMBA	Simplified Market Based Allocator – Load Factor specific allocator as defined in Section 5.00
TR	Combined Tax rate as defined in Section 5.0
WCAopd	Demand charges allowable for working capital application as defined in Section 6.1.
WCFopd	Working Capital factor allowable per billed off-peak sales associated with demand charges allocated to the off-peak period as defined in Section 10.0
WCRopd	Working Capital reconciliation adjustment associated with off-peak demand charges balance account 175.14 balance as outlined in Section 10.0.
x	Designates Load Factor specific allocation of costs based on Simplified Market Based Allocation factors, as determined in the Company's most recent rate proceeding.
PS_{op}^{x}	Portion of test year Local Production Capacity and Storage Costs, as defined in Section 5.00, allocated to off-peak period firm sales through the CGAC as determined in the Company's most recent rate proceeding.

Off-Peak Commodity Factor (CFop) Formula

$$CFop^{x} = \frac{Cop^{x} - NCCCop^{x}}{OP : Sales^{x}} + RFopc + WCFopc$$

and:

$$Cop^{X} = Sum{:}OPC^{X} - BOao^{X} - INJop^{X} - LIQop^{X}$$

and:

$$BOao^{X} = [(BOop - (BOvolop \times (TPop/TPvolop)))\ SMBA^{X}\ ]$$

and:

$$RFopc = Ropc/OP{:}Sales$$

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and:

$$WCFopc = \frac{\dfrac{[(WCAopc \times CC)-(WCAopc \times CD)]}{(1 - TR)} + (WCAopc \times CD) + WCRopc}{OP : Sales}$$

and:

WCAopc = Cop (DL/365)

Where:

BOao	LNG Boil-off allocation as defined in Section 9.00.
BOop	Cost of LNG Boil-off during the off-peak period.
BOvolop	LNG Boil-off volumes purchased in the off-peak period.
CC	Weighted cost of capital as defined in Section 5.00.
CD	Weighted cost of debt as defined in Section 5.00.
Cop	Commodity Charges billed to the off-peak period as defined in Section 5.00
DL	Number of days lag from the purchase of gas from suppliers to the payment by customers. See Section 10.00.
INJop	Injections into underground storage during the off-peak period.
LIQop	Liquefactions into storage during the off-peak period.
NCCCop	Non-core commodity costs allocated to the off-peak period as defined in Section 6.05.
OP:Sales	Forecasted sales volumes associated with the off-peak period.
OPC	Commodity charges associated with gas supply sent out in the off-peak season as defined in Section 5.00.
RFopc	Off peak commodity charge reconciliation adjustment factor per billed off peak sales volume associated with commodity charges related to the off-peak period.
Ropc	Reconciliation Adjustment Cost - Account 175.13 balance, inclusive of the associated Account 175.13 interest, as outlined in Section 9.00.
TPop	Total pipeline commodity purchase charges for the off-peak period.
TPvolop	Total pipeline purchase volumes for the off-peak period.
TR	Combined Tax rate as defined in Section 5.00.
WCAopc	Commodity charges allowable for working capital application as defined in Section 10.00.
WCFopc	Working Capital allowable per off-peak sales volume associated with commodity charges allocated to the off-peak period as defined in Section 10.00.
WCRopc	Working Capital reconciliation adjustment associated with off-peak commodity charges - Account 176.14 balance, as outlined in Section 10.00.

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x Designates Load Factor specific allocation of costs, based on Simplified Market Based Allocation factors.

7.0 Interruptible Sales, Off-System Sales and Capacity Release Revenues

A threshold level of margins will be established annually and separately for Interruptible Sales, Off-System Sales and Capacity Release Revenues. Any margins earned in excess of the predetermined level shall be divided between the Company and its firm sales customers under a 25/75 sharing arrangement. The threshold level of margins shall be adjusted to reflect additions or losses from Customers who switch from FT, FS or Interruptible Transportation ("IT") to IS and conversely, from IS to FT, FS or IT. The Company shall adjust the threshold level annually to reflect Interruptible Sales, Off-System sales, and capacity release revenues for the twelve-month period ending April 30 of each year.

Margins from Interruptible Sales, Off-System Sales and Capacity Release will be reflected as separate credits in the peak season GAF and shall be calculated as the sum of the following:

(1) 100% of the margins earned up to the predetermined threshold level.
(2) 75% of the margins earned in excess of the predetermined threshold level.

8.0 Gas Suppliers' Refunds - Accounts 265.85 and 265.86

Refunds from upstream capacity suppliers and suppliers of gas are credited to Account 265.85, "Refund-November" if received during the months of March through August, and to Account 265.86 "Refund-May", if received during the months of September through February.

A refund program shall be initiated with each semiannual GAF filing and shall remain in effect for a period of one year. The balance in Account 265.85 shall be placed into a refund program with each November filing. The balance in Account 265.86 shall be placed into a refund program with each May filing. The total dollars to be placed into a given refund program shall be net of over/under-returns from expired programs plus refunds received from suppliers since the previous program was initiated. The Company shall track and report on all Account 265.85 and Account 265.86 activities. If during any twelve-month period commencing with the billing month of November for Account 265.85 and May for Account 265.86, the projected supplier refund factor is less than one-hundredth of a cent per therm ($0.0001), the respective supplier refund account balance shall be transferred into Account 175.26 or Account 175.16 for the November and May filings respectively.

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Gas Supplier's Refund Factors

R1 The per unit supplier refund associated with the Refund – May program. The following formula shall be used to calculate the R1 factor.

$$R1 = \frac{R1\$ + I}{A{:}Sales}$$

Where:

R1$	Ending balance in Account 265.86 "Refund – May"
I	Total forecasted interest calculated on the R1$ balance computed at the consensus prime rate as reported in the *Wall Street Journal* based on a 365 day year.
A:Sales	Forecasted annual firm sales volumes.

R2 The per unit supplier refund associated with the Refund – November program. The following formula shall be used to calculate the R2 factor.

$$R2 = \frac{R2\$ + I}{A{:}Sales}$$

Where:

R2$	Ending balance in Account 265.85 "Refund – November"
I	Total forecasted interest calculated on the R2$ balance computed at the Federal Reserve Prime Rate based on a 365 day year.
A:Sales	Forecasted annual firm sales volumes.

9.0 Reconciliation Adjustments – Other than Working Capital

(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.

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ii. Charges associated with transmission capacity procured by the Company to serve base load requirements in the peak season.
iii. Charges associated with upstream storage and transmission capacity procured by the Company to serve firm load in excess of base load requirements in the peak period, plus a reallocation of a portion of such charges incurred in the off-peak season to serve firm load.
iv. Charges associated with peaking, production and storage capacity to serve firm load in the peak season as determined in the test year of the Company's most recent rate proceeding and allocated to firm sales storage service.
v. Credits associated with Non-Core Sales Margins or economic benefits from capacity release, off-system sales for resale and interruptible sales margins allocated to the firm sales service.
vi. Credits associated with daily imbalance charges billed transportation customers in the peak period.
vii. Credits associated with Capacity Exempt Customer Reliability Charges billed to Capacity Exempt Customers in the peak period in accordance with M.D.T.E. No. 35, Section 13.12.
viii. Peak demand Carrying Charges as defined in Section 5.00.

(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.
ii. Credit non-core commodity costs assigned to non-core customers to which the CGAC does not apply, as defined in Section 6.06 (NCCCp).
iii. Inventory finance charges (FC).
iv. Peak commodity Carrying Charges as defined in Section 5.00.

(c) Capacity Costs Allowable Per Off-Peak Demand Formula shall be:
i. Charges associated with transmission capacity and product demand procured by the Company to serve base load requirements in the off peak season.
ii. Charges associated with transmission capacity and product demand procured by the Company to serve firm load in excess of base load requirements in the off-peak period
iii. Credits associated with daily imbalance charges billed transportation customers in the off peak period.

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iv. Off-peak demand Carrying Charges as defined in Section 5.00.
v. Other A & G and Acct. 851 charges associated with peaking production and storage capacity to serve firm load in the off-peak season as determined in the test year of the Company's most recent rate proceeding and allocated to firm sales storage service

(d) Gas Ćosts 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 purchases in the off-peak period, less the cost of injections and liquefactions into storage.
ii. Credits associated with Non-core commodity costs from non-core sales to which the GAF is not applied, as defined in Section 5.00.
iii. Off-peak commodity Carrying Charges as defined in Section 5.00.

(2) **Calculation of the Reconciliation Adjustments**

Account 175 contains the accumulated difference between gas cost revenues and the actual monthly gas costs incurred by the Company. The Company shall separate Account 175 into Peak Demand (Account 175.21), Peak Production and Storage Demand (175.22), Peak Commodity (Account 175.23), Off-Peak Demand (Account 175.11), Off-Peak Production and Storage Demand (175.12) and Off-Peak Commodity (Account 175.13). Account 175.21 shall contain the accumulated difference between revenues toward capacity costs calculated by multiplying the Peak Demand Factor for the High and Low Load Factor classes, (DFp^X) times monthly firm sales volumes for High and Low Load Factor classes, and the total capacity costs allowable per the peak demand formula. Account 175.22 shall contain the accumulated difference between revenues toward gas costs as calculated by multiplying the Peak Commodity Factor for the High and Low Load Factor classes, (CFp^X) times monthly firm sales volumes for High and Low Load Factor classes, and the total commodity costs allowable per the peak commodity formula. Account 175.22 shall contain the accumulated difference between revenues as calculated by multiplying the Peak Production and Storage Demand Factor for the High and Low Load Factor class, (PS_p^x) times monthly firm sales volumes forthe High and Low Load Factor classes, and the total production and storage costs allowable per the peak production and storage demand formula. Account 175.11 shall contain the accumulated difference between revenues toward capacity costs calculated by

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multiplying the Off-Peak Demand Factor for the High and Low Load Factor classes, ($DFop^{X}$) times monthly firm sales volumes for the High and Low Load Factor classes, and the total capacity costs allowable per the off-peak demand formula. Account 175.13 shall contain the accumulated difference between revenues toward gas costs as calculated by multiplying the Off-Peak Commodity Factor for the High and Low Load Factor classes, ($CFop^{X}$) times monthly firm sales volumes for the High and Low Load Factor classes, and the total commodity costs allowable per the off-peak commodity formula. Account 175.12 shall contain the accumulated difference between revenues as calculated by multiplying the Off-Peak Production and Storage Demand Factor for the High and Low Load Factor classes, (PS_{op}^{x}) times monthly firm sales volumes for the High and Low Load Factor classes, and the total production and storage costs allowable per the off-peak production and storage demand formula.

Carrying Charges as defined in Section 5.00 shall be added to each end-of-the-month balance. The peak demand reconciliation adjustment factor (RFpd) shall be determined for use in the peak GAF calculation by dividing the peak demand account (175.21) balance as of the peak reconciliation date, by the forecasted sales volume associated with the peak period. The peak production & storage demand reconciliation adjustment factor (RFppsd) shall be determined for use in the peak GAF calculation by dividing the peak production and storage demand account (175.22) balance as of the peak reconciliation date, by the forecasted sales volume associated with the peak period. The peak commodity reconciliation adjustment factor (RFpc) shall be determined for use in the peak GAF calculation by dividing the peak commodity account (175.23) balance as of the peak reconciliation date, by the forecasted sales volume associated with the peak period. The off-peak demand reconciliation adjustment factor (RFopd) shall be determined for use in the off peak GAF calculation by dividing the off-peak demand account (175.11) balance as of the off-peak reconciliation date, by the forecasted sales volume associated with the off-peak period. The off-peak production and storage demand reconciliation adjustment factor (RFoppsd) shall be determined for use in the off-peak GAF calculation by dividing the off-peak production and storage demand account (175.12) balance as of the off-peak reconciliation date, by the forecasted sales volume associated with the off-peak period. The off-peak commodity reconciliation adjustment factor (RFopc) shall be determined for use in the off-peak GAF calculation by dividing the off-peak commodity account (175.13) balance as of the off-peak reconciliation date, by the forecasted sales volume associated with the off-peak period.

The peak period reconciliation will be filed thirty (30) days prior to the peak period GAF filing, which is seventy-five (75) days prior to the effective date.

The off-peak period reconciliation shall be filed thirty (30) days prior to the off-peak

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period GAF filing, which is seventy-five (75) days prior to the effective date.

10.0 Working Capital Reconciliation Adjustments

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

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

i. Charges associated with upstream storage, transmission capacity, and product demand procured by the Company to serve firm load in the peak season.
ii. Charges associated with transmission capacity procured by the Company to serve base load requirements in the peak season.
iii. Charges associated with upstream storage and transmission capacity procured by the Company to serve firm load in excess of base load requirements in the peak period, plus a reallocation of a portion of such charges incurred in the off-peak season to serve firm load.
iv. Carrying Charges

(b) Working Capital 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 costs 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 liquefactions into storage.
ii. Non-Core Commodity Costs associated with non-core sales to which the GAF is not applied.
iii. Carrying charges.

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

i. Charges associated with transmission capacity procured by the Company to serve base load requirements in the off peak season.
ii. Charges associated with upstream storage and transmission capacity procured by the Company to serve firm load in excess of base load requirements in the off-peak period.
iii. Carrying charges.

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(d) Working Capital 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 purchases in the off-peak period, less the cost of injections and liquefactions into storage.

ii. Non-core commodity costs associated with non-core sales to which the GAF is not applied, as defined in section 6.05.

iii. Carrying charges.

(2) The peak and off-peak, demand, and commodity 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.

(3) The peak and off-peak, demand, and commodity working capital allowances shall each be calculated by applying the Company's weighted cost of capital to each working 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 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) Calculation of the Reconciliation Adjustments

Accounts 175.14, 175.13, 175.24, and 175.23 contain the accumulated difference between working capital allowance revenues and the actual monthly working capital allowance costs as calculated from actual monthly costs for the Company plus Carrying Charges as defined in Section 5.00.

The components of the Company's purchased gas days lag shall be recalculated each season based upon actual CGAC seasonal data. This recalculated days lag will be used in the calculation of the working capital allowance revenues. Each Account 175 shall contain the accumulated difference between revenues toward the working capital allowance and the working capital allowance.

The peak demand working capital reconciliation adjustment shall be determined for use

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in the peak demand factor calculations incorporating the peak demand working capital account 175.14 balance as of the peak reconciliation date designated by the Company. A peak commodity working capital reconciliation adjustment shall be determined for use in the peak commodity factor calculations incorporating the peak commodity working capital account 175.13 balance as of the peak reconciliation date designated by the Company. An off-peak working capital reconciliation adjustment (WCRopd) shall be determined for use in the off-peak demand factor calculations incorporating the off-peak demand working capital account (175.24) balance as of the off-peak reconciliation date designated by the Company. An off-peak commodity working capital reconciliation adjustment (WCRopc) shall be determined for use in the off-peak commodity working capital account (175.23) balance as of the off-peak reconciliation date designated by the Company.

11.0 Application of GAF to Bills

The Company will employ the GAFs as follows: The peak season rates to each Load Factor class shall be calculated by adding the respective peak demand factor and the peak commodity factor. The off-peak season rates to each Load Factor class shall be calculated by adding the respective off-peak demand factor and the off-peak commodity factor. The GAFs ($/therm) for each Load Factor class for each season shall be calculated to the nearest one-hundredth of a cent per therm ($0.0001) and will be applied to each customer's monthly sales volume within the corresponding Load Factor class.

12.0 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 Company's standardized forms approved by the Department. Required filings include 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 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.

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13.0 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 10 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 GAF.

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

14.0 Customer Notification

The Company will design a notice, which explains in simple terms to customers the GAF, the nature of any change in the GAF and the manner in which the GAF is applied to the bill. 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.

15.0 Bad Debt Allowance

15.01 Purpose

The purpose of this provision is to establish a procedure that, subject to the jurisdiction of the Department, allows Bay State to adjust, on a semi-annual basis, its rates for the recovery of Bad Debt Expense

15.02 Bad Debt (BDF) Formula

The Bad Debt (BDF) Formula shall be computed on an annual basis using forecasts of bad debt expense associated with gas costs, gas costs, carrying charges, sales volumes, and a working capital allowance. Forecasts may be based on either historical data or Company projections, but must be weather-normalized. Any projections must be documented in full with each filing. The forecast of bad debt expense associated with gas costs shall be based on the Company's projected gas costs in the respective seasonal GAF filings and the percent of net write-offs to total firm revenues as determined in the

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Company's last rate proceeding.

The calculation at the beginning of the off-peak season shall be on a projected annual basis. The calculation at the beginning of the peak season will update the remaining months of the projected annual period with actual bad debt expenses and collections for the available months and projections for the remaining months of the annual period. The following formula shall be used to calculate the Bad Debt factor.

$$BDF = \frac{BD + RAbd + WCbd}{A{:}Sales}$$

and:

$$WCbd = \frac{(WCAbd * CC) - (WCAbd * CD)}{(1 - TR)} + (WCAbd * CD)$$

and:

$$WCAbd = BD * (DL/365)$$

Where:

A:Sales	Forecast annual sales volumes.
BD	Forecast Bad Debt Expense as defined in Section 5.00; derived by multiplying the forecast annual gas costs by the percent of annual net write-offs to annual firm revenues as determined in D.T.E. 05-27.
CC	Weighted cost of capital as defined in Section 5.00.
CD	Weighted cost of debt as defined in Section 5.00.
DL	Number of days lag from the purchase of gas from suppliers to the payment by customers.
RAbd	Bad Debt Expense reconciliation adjustment - Account 175.31 balance.
TR	Combined Tax rate as defined in Section 5.00.
WCAbd	Bad Debt allowable for working capital application defined as the costs associated with the gas cost portion of bad debt incurred by the Company to serve firm load.
WCbd	Working Capital Allowance associated with the gas portion of bad debt for the period including the Pretax Weighted Cost of Capital as defined in Section 5.00.

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15.03 Bad Debt Reconciliation Adjustment

Account 175.31 shall contain the accumulated difference between the annual revenues toward bad debt, as calculated by multiplying the bad debt factors (BDF) times monthly firm sales volumes, and the annual allowed Bad Debt expenses, allowed working capital on Bad Debt and Carrying Charges as defined in Section 5.00.

An annual bad debt reconciliation adjustment (RAbd - as defined in Section 15.02) shall be determined for use in the bad debt factor calculations incorporating the bad debt working capital account (175.32) balance as of the reconciliation date designated by the Company.

(a) Costs Allowable per Bad Debt Formula shall be:
  i. Un-collectable gas costs incurred by the Company to serve firm sales load, as determined by deriving the portion of actual net write-offs associated with gas cost collections.
  ii. Account 175.32 – Bad Debt, Carrying Charges.
  iii. Working Capital Gas Costs Allowable per Bad Debt Formula, which shall be charges associated with bad debt incurred by the Company to serve firm sales load and applied to the working capital formula.