Rochester Gas and Electric Corporation
PSC Case 98-G-1589
January 28, 2000

NIXON PEABODY LLP
ATTORNEYS AT LAW
Clinton Square
Post Office Box 1051
Rochester, New York 14603-1051
(716) 263-1000
Fax: (716) 263-1600
Direct Dial: (716) 263-1529
E-Mail: swidger@nixonpeabody.com

January 27, 2000

Public Service Commission
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Hon. Debra Renner
Acting Secretary
Public Service Commission
3 Empire State Plaza
Albany, New York 12223

RE: Case 98-G-1589 - In the Matter of Rochester Gas and Electric Corporation's Plans for Gas Rates and Restructuring

Case 97-G-1380 - In the Matter of Issues Associated with the Future of the Natural Gas Industry and the Role of Local Gas Distribution Companies

Dear Acting Secretary Renner:

On behalf of Rochester Gas and Electric Corporation ("RG&E," the "Company") we are submitting herewith twenty-five (25) copies of the Company's Filing in compliance with the Commission's Order Approving Petition, issued September 30, 1999 in Case 98-G-1589, and the Commission's Policy Statement Concerning the Future of the Natural Gas Industry in New York State and Order Terminating Capacity Assignment, issued November 3, 1998 in Case 97-G-1380 et al. (the "Policy Statement"). By this Filing, RG&E seeks to establish rates for natural gas service through June 30, 2002 and to implement a restructuring of the Company's gas business. A summary of the Company's complete proposal can be found in Appendix B to the Filing.

As the Commission is aware, RG&E's gas base rates have been "frozen" since July 1, 1994. Although the Filing presents all the data necessary to support a significant gas rate increase, the Company has not, at this time, sought a specific increase. Instead, RG&E believes that, through the collaborative negotiations that it expects will follow this Filing, it is possible that the need for the full amount of this otherwise justified increase may be ameliorated.

In addition to complying with the requirements of the Policy Statement, as further elaborated upon in the Commission's Order Clarifying Gas Policy Statement, issued April 1, 1999, this Filing fulfills RG&E's obligations under the September 14, 1999 Proposal for

Capacity Release Revenue Imputation and Capacity Cost Mitigation Issues and Framework for Resuming Settlement Negotiations that was approved in the aforementioned Order Approving Petition. Specifically, in this document, the Company has incorporated an updated, public version of the Report to the Staff of the Department of Public Service on Natural Gas Capacity Cost Mitigation the Company submitted on November 29, 1999. In addition, as called for by the approved Proposal, RG&E has included a discussion of its continuing work on retail access program improvements.

Copies of this Filing are being served today on Chief Administrative Law Judge Judith Lee and Administrative Law Judge Walter Moynihan, as well as on all parties to Case 98-G-1589. RG&E desires to commence negotiations regarding this Filing as soon as feasible, consistent with the conditions set forth in the Policy Statement. While RG&E recognizes that actual negotiations may not begin until thirty (30) days have elapsed from the date of this Filing, the Company believes that it would be both efficient and consistent with the public interest for the parties to meet in advance of the expiration of the thirty-day period. At such a meeting, logistics and other administrative details could be addressed, thereby permitting the parties to make the best possible use of their time, once negotiations are permitted to begin. The Company will take the initiative to contact the parties with regard to these matters.

Any questions regarding this Filing should be directed to Mark Marini, Manager of Regulatory Affairs of RG&E ((716) 771-4692), or the undersigned.

In addition to the twenty-five (25) copies of the RG&E document and this cover letter for filing, we are enclosing one (1) extra copy of each and ask that you kindly acknowledge receipt of this Filing by date-stamping those extra copies of this letter and the document and returning them to us in the enclosed postage-paid envelope.

Very truly yours,

Stanley W. Widger, Jr.

Stanley W. Widger, Jr.

Enclosures
cc & encs: Hon. Judith A. Lee
Hon. Walter T. Moynihan
All Parties

STATE OF NEW YORK
BEFORE THE
PUBLIC SERVICE COMMISSION

CASE 98-G-1589 -	In the Matter of Rochester Gas and Electric Corporation's Plans for Gas Rates and Restructuring
CASE 97-G-1380 -	In the Matter of Issues Associated with the Future of the Natural Gas Industry and the Role of Local Gas Distribution Companies

FILING

OF

ROCHESTER GAS AND ELECTRIC CORPORATION

January 28, 2000

TABLE OF CONTENTS

Page

SECTION I - BACKGROUND AND OVERVIEW I-1

A. INTRODUCTION I-1

B. THE REGULATORY ENVIRONMENT I-4

C. RG&E-SPECIFIC HISTORY I-6

D. RELATIONSHIP TO "GENERIC" AND "COMMON" ISSUES I-9

1. GENERIC ISSUES I-10
   a. System Operation and Reliability I-10
   b. Market Power I-12
2. COMMON ISSUES I-16
   a. Provider of Last Resort I-16
   b. Other Common Gas/Electric Issues I-17

E. IMPLEMENTATION ISSUES I-17

1. COMPETITION AND CUSTOMER CHOICE I-18
2. PROVIDER OF LAST RESORT I-21
3. RELIABILITY I-21
   a. Managing Daily Flows I-22
   b. Managing Hourly Flows I-25
   c. Managing Flows by Delivery Point I-26
   d. Ensuring Reliable Deliveries I-27
4. CUSTOMER EDUCATION I-28

F. GOALS I-30

G. SUMMARY OF PROPOSALS I-31

SECTION II - CAPACITY COST MITIGATION II-2

SECTION III – LONG TERM RATE PLAN III-1

A. REVENUE REQUIREMENTS III-1

1. REVENUE FORECAST III-2
   a. For Retail and SC 5 Forecasted Sales III-2

b. For SC 3 Forecasted Sales III-3
c. Normalized Margins Per Therm Were Calculated By Restating The Actual 1999 Margins To Eliminate The Effect Of Weather. To Do This, The Following Steps Were Followed: III-3
d. Applicable Gas Cost Adjustment ("GCA") Rates, Transportation Rate Adjustments And Revenue Tax Rates Were Applied To Develop Rate Year Revenues. III-4

2. EXPENSE FORECAST III-4
3. AMORTIZATIONS AND BOOK DEPRECIATION III-5
4. TAXES, OTHER THAN INCOME III-6
5. FEDERAL INCOME TAXES III-7
6. AVERAGE RATE BASE III-7
7. COST OF CAPITAL III-8

B. **REVENUE REQUIREMENT PROPOSAL** III-9

1. NEGOTIATION III-9
2. MANDATE, CATASTROPHIC EVENT, COMPETITION IMPLEMENTATION COSTS III-10
3. COST ADJUSTMENTS ARISING DURING NEGOTIATIONS III-11

SECTION IV – PLAN TO FURTHER UNBUNDLE RATES IV-1

A. **STRATEGY** IV-1
B. **RATE DESIGN PROPOSALS** IV-2

1. SERVICE CLASSIFICATION NO. 1 ..... IV-2
a. Implementation Of New Gas Cost Adjustment Regulations IV-2
b Increasing The Customer Charge IV-3
c. Redesign Of Block Rates IV-4
2. SERVICE CLASSIFICATION NO. 3 ..... IV-4
3. SERVICE CLASSIFICATION NO. 5 ..... IV-4
a. Increasing The Customer Charge IV-4
b. Redesign Of Block Rates IV-4
4. SERVICE CLASSIFICATION NO. 2 AND SERVICE CLASSIFICATION NO. IV-4
5. SERVICE CLASSIFICATION NO. 7 AND SERVICE CLASSIFICATION NO. 8 ..... IV-4

C. **CUSTOMER BILL IMPACTS** IV-5
D. **FACTOR OF ADJUSTMENT** IV-5
E. **RETAILING BACKOUT CREDIT** IV-5
F. **BALANCING** IV-5
G. **TRANSITION COST RECOVERY** IV-6

SECTION V - CUSTOMER EDUCATION PLAN V-1

SECTION VI - FACILITATING THE MOVE TO COMPETITION VI-1

A. **THE NATURE OF DISTRIBUTION SERVICE** VI-1
B. **MANAGING GAS DELIVERIES** VI-4
C. **COMMUNICATIONS BETWEEN GAS MARKETERS AND THE UTILITY** VI-7
D. **PROPOSAL TO DEREGULATE RETAIL COMMODITY PRICES** VI-8
E. **OBLIGATION TO SERVE** VI-9

APPENDIX A -- IMPROVEMENTS TO TRANSPORTATION GAS PROGRAM
APPENDIX B -- GAS RESTRUCTURING PROPOSAL - SUMMARY
APPENDIX C -- UPDATED REPORT ON NATURAL GAS CAPACITY COST MITIGATION
APPENDIX D -- REVENUE REQUIREMENT EXHIBITS
APPENDIX E -- REPORT ON THE DETERMINATION OF THE COST OF COMMON EQUITY
APPENDIX F -- CUSTOMER BILL IMPACTS
APPENDIX G -- MARGINAL CUSTOMER COST OF SERVICE
APPENDIX H -- PROPOSED TRANSPORTATION GAS TARIFF CHANGES
APPENDIX I -- MANAGING GAS DELIVERIES
APPENDIX J -- DELIVERY POINT OPERATING CONSTRAINTS
APPENDIX K -- COMMUNICATIONS PROTOCOL
APPENDIX L -- LOW INCOME ASSISTANCE PARTNERSHIP PROGRAM

SECTION

I

BACKGROUND AND OVERVIEW

A. INTRODUCTION

Rochester Gas and Electric Corporation ("RG&E," the "Company") makes this filing pursuant to the Company's Proposal for Capacity Release Revenue Imputation and Capacity Cost Mitigation Issues and Framework for Resuming Settlement Negotiations (the "Proposal") filed September 14, 1999 and approved by the Commission in its Order Approving Petition issued September 30, 1999 (the "September 30 Order") in Case 98-G-1589.[1] More specifically, and consistent with the terms of the Proposal as approved, this filing addresses the rate and restructuring issues identified in the Commission's Policy Statement Concerning the Future of the Natural Gas Industry in New York State and Order Terminating Capacity Assignment issued November 3, 1998 (the "Policy Statement") in Case 97-G-1380[2] and the Commission's Order Clarifying Gas Policy Statement issued April 1, 1999 (the "Clarifying Order").

The Policy Statement articulates the Commission's "vision for the future of the natural gas industry in New York in an increasingly competitive market" as a series of eight goals:

(1) Effective competition in the gas supply market for retail customers;
(2) Downward pressure on customer gas prices;
(3) Increased customer choice of gas suppliers and service options;
(4) A provider of last resort;
(5) Continuation of reliable service and maintenance of operations procedures that treat all participants fairly;
(6) Sufficient and accurate information for customers to use in making informed decisions;

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1 In the Matter of Rochester Gas and Electric Corporation's Plans for Gas Rates and Restructuring (the "RG&E Restructuring Proceeding").

2 In the Matter of Issues Associated with the Future of the Natural Gas Industry and the Role of Local Gas Distribution Companies.

(7) The availability of information that permits adequate oversight of the market to ensure its fair operation; and

(8) Coordination of Federal and State policies affecting gas supply and distribution in New York State.

Policy Statement at 4.

Fundamentally, RG&E shares the Commission's vision and believes that the goals, as stated above, provide a reasonable set of objectives for achieving that vision. RG&E also shares the Commission's view, inherent in the Policy Statement, that success in realizing the vision depends on a well articulated, practicable transition process. Toward that end, the Policy Statement envisions a three-part process to be pursued in parallel: (1) "discussions with each LDC on an individualized plan"; (2) "collaboration among staff, LDCs, marketers, pipelines, and other stakeholders on a number of key generic issues . . . [including] future system operation and reliability issues. . . [and] market power issues"; and (3) "coordination of issues that are also faced by electric utilities . . . [including] provider of last resort issues, as well as a plan to allow competition in other areas, such as metering, billing, and information services" (Policy Statement at 9).[3]

This filing presents RG&E's "individualized plan" in accordance with the Policy Statement's requirements. These requirements envision the presentation of comprehensive proposals that will be distributed to interested parties in preparation for settlement negotiations. Specifically, the Policy Statement requires local distribution companies ("LDCs") to address the following six issues in individual plans:

(1) A strategy to hold new capacity contracts to a minimum;

(2) A quantification of potential stranded costs and a plan to mitigate and manage them;

(3) A long term rate plan with a goal of reducing or freezing rates;

(4) A plan to further unbundle rates which would

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3 The third group of issues is to be addressed "in conjunction with the electric restructuring proceedings" (Policy Statement at 9).

(i) separate distribution and gas purchase (upstream) costs;

(ii) separately identify distribution cost elements;

(iii) identify changes which would promote retail competition;

(iv) propose other rate design changes, if appropriate.

(5) A plan to enhance consumer education programs and facilitate customer participation;

(6) The possibility of a more aggressive role for LDCs in facilitating the move to a competitive market.

Policy Statement at 8; footnote omitted.[4]

This filing is intended to provide the basis for negotiations, as contemplated in the Policy Statement and in the Clarifying Order, on RG&E's individualized plan to effectuate the LDC-specific provisions of the vision presented in the Policy Statement. Because the Company has been engaged in negotiations with Staff and interested parties over much of the past 18 months, certain elements of this filing will be familiar to these parties. Other elements, however, reflect changes in approach that either incorporate further evolution in the Company's thinking on these issues or are intended to eliminate impediments identified in prior negotiations. In addition to the individualized plan, this filing discusses, where necessary and relevant to the treatment of "individual" issues, the two other basic elements of the Commission's overall approach under the Policy Statement, generic issues facing LDCs and coordination of issues also faced by electric utilities. It must be borne in mind that much of the work on these issues has yet to be completed;[5] any comment on them in this filing will be limited.

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[4] In the omitted footnote, to item (2), the Commission stated:

> At a minimum, the LDC must demonstrate that it has made reasonable efforts to minimize strandable costs in compliance with the Commission's directives in Case 93-G-0932, including the requirements of the Order Clarifying the April 1998 Excess Capacity Filing Requirements, issued September 4, 1997.

Policy Statement at 8, fn. 1.

[5] On December 21, 1999, the Commission issued its Order Concerning Reliability in Case 97-G-1380. This Order requires a series of ongoing activities with respect to reliability issues. RG&E expects that, as negotiations concerning this filing progress, there will be ample opportunity to discuss the impact of these generic reliability issues in the context of the Company's specific plan.

Further, this filing reports on RG&E's ongoing activities with regard to two related matters that were identified in the Proposal: efforts to mitigate pipeline capacity costs; and work on retail access program improvements with marketers operating in the Company's service territory. The first of these topics is addressed in an update to RG&E's Report to the Staff of the Department of Public Service on Natural Gas Capacity Cost Mitigation (the "Capacity Report") that was submitted November 29, 1999.[6] The Company's Updated Report on Natural Gas Capacity Cost Mitigation (the "Updated Report") is discussed in Section II of this filing and is attached hereto as Appendix C. RG&E's efforts to improve transportation gas service are discussed in Section VI C, below and in Appendices A and K.

As this filing confirms, RG&E is committed to competition in the provision of natural gas service for the benefit of its customers. The process of opening up the market to competition is already well under way. The plans contained in this filing are designed to foster and enhance such competition in a manner that recognizes and deals fairly with the interests of all stakeholders: customers, marketers, shareholders and regulators.

In this Section of the filing, RG&E will describe the regulatory background, pertinent recent history of the Company's gas operations, and major issues and policies that have a bearing on the subject matter of this submission.

B. THE REGULATORY ENVIRONMENT

Although the restructuring of the natural gas market in New York can be traced back at least as early as the 1980s with the implementation of large-volume transportation service by LDCs, the "modern era" of restructuring has its origins in Case 93-G-0932, Proceeding on

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[6] The Capacity Report and Supplement Nos. 1 and 2, dated December 10, 1999 and December 16, 1999, respectively, were submitted as trade secret documents pursuant to the Commission's regulations (16 NYCRR §§ 6-1.3, 6-1.4) and were granted provisional status as such. In view of the public nature of the instant filing, the Updated Report has been modified to avoid disclosure of trade secret information on file with the Commission.

Motion of the Commission to Address Issues Associated with the Restructuring of the Emerging Competitive Natural Gas Market (the "Gas Restructuring Case"). On December 20, 1994, the Commission issued Opinion No. 94-26,[7] which adopted a broad range of specific policies applicable to the gas industry in New York. For present purposes, several are relevant; they include: (1) recognition of distinctions between core customers and non-core customers, whereby market pricing to non-core customers is generally acceptable; (2) providing an incentive to LDCs to release excess pipeline capacity[8] and allowing a degree of discretion as to pricing of released capacity and/or other services; (3) requiring LDCs to offer firm customers access to the LDC's upstream facilities; and (4) allowing aggregation of groups of smaller customers to permit them to be treated as units for purposes of acquiring gas as an alternative to full retail service from the LDC, and encouraging LDCs to increase or eliminate minimum volume requirements.[9]

Over the past five years, RG&E and other LDCs have actively implemented the foregoing policies and others through tariff filings and settlements. During this time, these policies have continued to evolve, and the Commission has addressed changes and refinements to them in a series of documents, the most comprehensive of which is the Policy Statement. The Commission's vision of the competitive market is not static, however; further orders have continued to define and refine that vision.[10] In addition, the work of Staff and other parties on some of the broader issues identified in the Policy Statement is ongoing, as discussed in Part D of this Section I, below.

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7 Opinion and Order Establishing Regulatory Policies and Guidelines for Natural Gas Distributors ("Opinion No. 94-26").

8 The Commission adopted a sharing mechanism whereby customers would be credited with 85 percent of margins received from capacity releases and shareholders would have the opportunity to retain 15 percent, unless a different mechanism is justified on a case-by-case basis. Opinion No. 94-26 at 8.

9 See Opinion No. 94-26 at 6-12.

10 Requirements relating to the assignment/release of capacity to marketers, for example, have undergone a series of changes. See, e.g., Case 97-G-1380, Order Concerning Assignment of Capacity, issued March 24, 1999, and subsequent Orders in the same proceeding.

In this filing, RG&E addresses not only the requirements of the Policy Statement, but also the requirements of other Commission Orders that apply to the subject matter. To the extent necessary in the explanation of the Company's proposal, the specific requirements of these Orders are discussed herein.

C. RG&E-SPECIFIC HISTORY

In August 1998, before the adoption of the Policy Statement, RG&E had initiated negotiations to implement a multi-year gas rate and restructuring plan as a successor to a 1995 Settlement that was set to expire at the end of October 1998.[11] The 1995 Settlement contained three major provisions. First, RG&E had agreed to absorb certain amounts related to gas supply and capacity costs. Second, the Company forewent a rate increase already approved by the Commission, as well as all potential rate increases through June 30, 1998, the effect of which was to freeze base rates at their July 1, 1994 levels. Third, for each year of its three-year term, the 1995 Settlement imputed a particular level of revenues representing targeted cost reductions from capacity release transactions.[12]

During negotiations on RG&E's 1998 rate and restructuring proposal, it appeared likely that the parties would not be able to resolve all pertinent issues prior to the expiration of the 1995 Settlement (i.e., by October 31 1998). Accordingly, RG&E, Staff and several other parties to the negotiations entered into an Interim Settlement Agreement dated October 16, 1998, which was approved by the Commission on November 9, 1998.[13] The Interim Settlement, which expired

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[11] This Settlement, dated August 15, 1995, was approved by the Commission on October 27, 1995. Case 94-G-1048 et al., Proceeding on Motion of the Commission to Investigate the Practices of Rochester Gas and Electric Corporation in the Acquisition of Pipeline Capacity and the related Costs, Opinion No. 95-18, Opinion and Order Approving Settlement Agreement.

[12] The revenue imputation for capacity release transactions was intended to mitigate, for the benefit of customers, the impact of the surplus capacity held by RG&E following the in-service date of the Empire State Pipeline ("Empire") in November 1993, as discussed in greater detail in the Updated Report (App. C).

[13] Case 98-G-1589, Order Freezing Base Rates, Limiting Mandatory Assignment of Capacity, and Resolving Other Issues.

June 30, 1999, maintained the existing base rate freeze, committed the Company to provide customers with a minimum $11.9 million reduction related to capacity release transactions,[14] provided for elimination of the requirement in the Company's tariff that suppliers providing service to customers under Service Classification Nos. 5 and 6 take assignment of a portion of the Company's upstream pipeline capacity, and resolved certain other matters relating to RG&E's Supply Portfolio Management Agreements and the Gas Cost Adjustment ("GCA").

After approval of the Interim Settlement, in February 1999, negotiations resumed with respect to RG&E's gas rate and restructuring plan, which had been revised and updated in certain respects, partly for the purpose of ensuring that all of the issues required by the Policy Statement were explicitly covered. Because negotiations as to RG&E's settlement proposal predated the issuance of the Policy Statement, and the proposal had been presented to, and discussed with, the negotiating parties under the assumption that such material and discussions were confidential in accordance with the Commission's confidentiality requirements,[15] the Company's renewed plan was treated as confidential. In its Clarifying Order of April 1, 1999, the Commission addressed how RG&E's unique situation – as the only LDC whose restructuring negotiations had begun before issuance of the Policy Statement – would be addressed:

> [T]o the extent the revenue requirement and other rate aspects of [RG&E's] proposal were distributed as confidential settlement documents, RG&E cannot rely on the documents as complying with the requirements of the Gas Policy Statement. Therefore, if [RG&E's settlement] negotiations prove unsuccessful, RG&E is obligated to bring itself into compliance with the Gas Policy Statement, as clarified herein, by submitting a public plan concerning the rate aspects called for in the Gas Policy Statement.

Clarifying Order at 2.

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[14] This capacity release revenue imputation incorporated an incentive to discourage releases of capacity that would increase the overall cost of gas to RG&E's customers. See Interim Settlement, Paragraph 5(c) at 7-9.

[15] See 16 NYCRR § 3.9.

At the time the Clarifying Order was issued, there was no need to modify the Company's filing (e.g., by making a public filing of the revenue requirement and other rate aspects of the proposal); negotiations were continuing and appeared promising. In June 1999, however, settlement negotiations reached a standstill and were suspended. The provisions of the Interim Settlement other than those pertaining to capacity release revenues, which ran through August 31, 1999, expired as of June 30, 1999. With no "replacement" settlement agreement in place with regard to the treatment of capacity release revenues, the $11.9 million imputed benefit to customers no longer existed and, at the end of August 1999, the Company filed a GCA statement that eliminated the impact of this imputation. On September 14, 1999, after discussions with Staff, the Company filed the Proposal that was subsequently approved by the Commission and that provided for this filing.

The Proposal, as approved by the Commission, addressed four principal areas. First, it continued to provide customers with a reduction in capacity costs of $11.9 million, consisting of $10.2 million relating to upstream capacity release transactions for the period September 1, 1999 through August 31, 2000, and $1.7 million from the expiration of a contract with Texas Eastern Transmission Corporation, which the Company determined not to renew. To the extent that RG&E realizes capacity release revenues and credits in excess of the $10.2 million, the overage will be shared by customers and shareholders, 95 percent and 5 percent, respectively, after subtraction of sharing payments made to the Company's portfolio manager, if any, for capacity release transactions.[16]

Second, as mentioned earlier in this Section, the Proposal provided for reporting by RG&E on its capacity cost mitigation activities, first in a filing to be submitted 60 days after approval of the Proposal (i.e., in the Capacity Report submitted to Staff on November 29, 1999),

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[16] The mechanics of implementing this provision of the Proposal are detailed in Appendix A to the Proposal.

and subsequently in an update to that Report to be included in this filing. Under the Proposal, Staff was to comment on the adequacy of the Company's efforts and plans; Staff did so by letter dated January 4, 2000.

Third, as indicated at the outset, the Proposal called for making this public filing within 120 days of approval.[17] Under the Proposal, and consistent with the Policy Statement, settlement negotiations are contemplated to resume as soon as feasible after the requisite 30-day interval following filing.

Fourth, and finally, the Proposal called for RG&E to continue its efforts to work with marketers to improve the retail access program through such measures as development of balancing services. The Company will discuss these efforts in this filing.

D. RELATIONSHIP TO "GENERIC" AND "COMMON" ISSUES

This filing addresses in detail all of the issues presented by the Policy Statement and the Proposal with the exception of the "key generic issues" to be addressed in the collaborative process ("future system operation and reliability" and "market power"), and coordination of issues common to the electric, as well as the gas, business ("provider of last resort" and "competition in other areas, such as metering, billing, and information services").[18] That is not to say that the "generic" and "common" issues are ignored herein. In RG&E's view, a successful multi-year settlement of rate and restructuring issues depends on anticipating and, where possible, incorporating the impact of any proposed resolution of these broad issues. In some cases, however, it may be necessary to postpone commitment to a specific course of action until particular generic or common issues are resolved.

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[17] As noted in the Proposal (p. 2), it was understood that portions of this filing would qualify for trade secret protection. See footnote 6, supra.

[18] See Policy Statement at 8-9.

Before turning to the heart of the Company's rate and restructuring plans, it is useful to review the status of the generic and common issues.

1. GENERIC ISSUES

a. System Operation and Reliability

Collaborative efforts regarding future system operation and reliability began in December 1999 and continued in three working groups of interested parties, as follows: (1) Communications Working Group, dealing with day-to-day communication protocols between LDCs, marketers and pipelines, especially during critical periods; (2) Capacity Requirements Working Group, considering the shorter-term issue of the capacity a marketer must hold to serve the market reliably; and (3) Capacity Dedication Working Group, addressing the longer-term issue of how to retain capacity available to serve the New York market. By its Order Concerning Reliability ("Reliability Order"), issued December 21, 1999 in Case 97-G-1380, the Commission reported on the status of the efforts by each of the three Working Groups, required LDCs to file a Gas Transportation Operating Procedures Manual and conforming tariff revisions, and issued for comment a series of questions pertaining to curtailment issues and Staff's recommended protocols for implementing a "default capacity requirement" for marketers.

As described in the Reliability Order, of the three working groups, only the Communications Working Group had reached consensus. That consensus is presented in the August 5, 1999 Report of the Working Group, attached to the Reliability Order, which recommended that LDC communications procedures be codified in the Gas Transportation Operating Procedures Manual and which was adopted in the Order. This working group, however, was unable to reach consensus regarding issues that may arise during times of curtailment and that may go beyond existing curtailment procedures. Accordingly, the

Commission issued for comment the "Curtailment Issues" listed in Appendix B to the Reliability Order.[19]

In defining the capacity a marketer must hold to reliably serve the market, the Capacity Requirements Working Group was charged with developing protocols to implement the Commission's requirement that "all marketers serving firm loads [must] demonstrate that they have firm, non-recallable, primary delivery point capacity to the citygate, but only for the winter season (November through March)"[20] (the "Five-Month Requirement") and with considering alternatives to the Five-Month Requirement. While the Capacity Requirements Working Group agreed that a "reliability forum" should be established to facilitate ongoing communication among LDCs, marketers, pipelines and others, the Group was unable to reach agreement on the Five-Month Requirement or any alternative to it.[21] Although there was general agreement that certain protocols would be required to implement capacity requirements for marketers, the Commission concluded that there was a need for further analysis of several specific issues, including the nature of the assets a marketer must hold to serve reliably, the upstream point at which the marketer must supply the gas, and the details of marketer compliance. Accordingly, the Commission issued for comment the Staff Recommended Protocols for Implementing the Default Capacity Requirement contained in Appendix C to the Reliability Order.[22]

The Capacity Dedication Working Group agreed on the broad principle that there is a need to tie pipeline capacity to the markets the capacity currently serves; but the Group was

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19 Comments are due 60 days after issuance of the Order and reply comments are due 75 days after issuance.

20 Case 97-G-1380, Order Concerning Assignment of Capacity, issued March 24, 1999, at 7.

21 During the same general time that the Capacity Requirements Working Group was considering these matters, the Commission, in an effort to ensure that marketers had sufficient capacity for the current winter, adopted a Staff proposal that marketers serving firm customers have firm, primary point delivery point capacity for the months of November through March, but allowed an alternative for marketers to have firm secondary point capacity and to pay the LDC a "standby" charge for backup service. Case 97-G-1380, Order issued August 19, 1999.

22 The deadlines for initial and reply comments are the same as those for the Curtailment Issues. See footnote 19, supra.

unable to reach consensus on the means of achieving that goal. In the Reliability Order, the Commission reviewed the complexities of this set of issues and concluded that the non-uniformity of LDC/pipeline contract terms, renewal/cancellation notice dates and the like "provides an opportunity to approach the transition incrementally, with opportunities for testing and correction where appropriate" (Reliability Order at 9). Concomitantly, the Commission observed that "[t]he proper balance among . . . objectives is best explored on an individual company basis" (ibid.). Among the issues the Commission identified are:

> (1) the level of capacity that should be relinquished relative to the overall level of capacity that the LDC requires, (2) the liquidity of the hub or trading points that the capacity connects to, (3) the level of marketer penetration and interest in capacity, (4) the potential for competition for relinquished capacity, and (5) options for replacing that capacity should the need arise.

Id. at 9-10.

The Commission stated that it would direct the Office of Hearings and Alternative Dispute Resolution to "establish a process for examining the capacity issues, including what capacity requirements should apply and the extent to which capacity availability requirements are appropriate in the context of the evolving gas market" (id. at 10).

RG&E will, of course, comply with the Reliability Order's requirements pertaining to the filing of a Gas Transportation Operating Procedures Manual and corresponding tariff amendments, and will participate in the comment procedures for the Curtailment Issues and Default Capacity Requirement. With regard to the remaining capacity issues, this filing addresses all of them in the context of RG&E's plans for dealing with the specific needs of its service area and the Company's relationships with marketers and customers.

b. Market Power

Collaborative efforts have not begun regarding the Policy Statement's charge to "examine and develop safeguards and monitoring mechanisms for market power issues in natural gas markets, particularly in light of the LDCs' exiting the merchant function" (Policy Statement at 9). The fact that this element of the collaborative process for generic issues has not progressed does not present a stumbling block to implementing RG&E's gas rate and restructuring plans.

RG&E's traditional dominance of the gas supply market in its service area – a direct consequence of the long-standing bundled character of the LDC function – began to change immediately after large-volume transportation-only service was approved in the 1980s. The Company's large-volume market, consisting primarily of large industrial and commercial customers, has grown to the point where annual transportation throughput constitutes approximately 45 percent of total Company throughput. Very few customers with throughput in excess of 5,000 dekatherms ("DT") per year remain as retail sales customers. Equally important, competitive suppliers are making significant inroads into the small-volume, non-residential market.

In terms of sheer numbers of customers, the residential market represents the greatest potential for shifting to competitive suppliers. Since the advent of the customer aggregation program under Service Classification Nos. 5 and 6, and as of the beginning of December 1999, approximately 7,000 residential customers have converted to alternative suppliers. The pace of residential migration has been, and continues to be, rapid.

It is reasonable to conclude from the foregoing empirical evidence that development of the competitive natural gas market in RG&E's service area is progressing well. There should be no concern that the Company's former dominance of the market, as a natural consequence of its monopoly provision of bundled service, will continue or will have any lasting effect on this open and rapidly developing market.

Turning from the existing state of the market to the Commission's vision of a market in which the LDC's merchant role is nearly or fully supplanted by other suppliers, the focus becomes: what is necessary for competition? There are, in RG&E's view, two basic underlying assumptions inherent in that inquiry. First, a competitive market is one in which consumer surplus is maximized. In other words, there exists, by operation of the market itself, the greatest opportunity for consumers to select from a number of suppliers at prices reflecting meaningful choice for consumers. The second assumption is that the results of these competitive conditions for any particular supplier are irrelevant to policymakers. That is, the manner in which the market is opened to competition should not be dependent on the particular circumstances of potential suppliers.

Simply put, viable competitive markets arise without centralized intervention when certain conditions exist. The most familiar condition is that "well-behaved" supply and demand curves adequately describe the behavior of market participants. The text book characterization of downward sloping curves leads to a stable balance of supply and demand. Effective competition also requires that there be no persistent lack of relevant knowledge on the part of suppliers or consumers. Where the potential rewards of participation in the market provide sufficient incentive for suppliers to invest in ensuring that their prospective customers have such knowledge, markets will flourish. Other potential barriers, such as lack of trained technical personnel, hardware and software, and marketing resources, must also be surmountable. These circumstances are not unique to supplying natural gas. Potential barriers exist in all fields of endeavor; this is precisely why some firms flourish and others perish. The Company believes that these issues present no barriers to the introduction of competition in the retail gas commodity market. Apparently, the Commission shares this view.

Subsidies offered to potential market entrants, however well-intentioned, must be avoided. Subsidizing the development of a competitive market is an oxymoron; a subsidy actually hinders competition. While past experience shows that subsidies are all too often employed as a means of "jump-starting" a market, their ultimate product is mischief. Perhaps their most pernicious effect is allowing relatively inefficient suppliers to persist in the marketplace with the troubling result that consumers are effectively misled into relying on weak participants and society's resources are misallocated to the subsidized entity.

Obviously, if the traditional regulated monopoly is replaced by an alternative – most likely unregulated – monopoly, a competitive market will not thrive. Among the factors that could lead to a monopoly under such conditions are technological factors whereby the average cost curve slopes downward over the relevant range of demand, resulting in such economies of scale that a single supplier, or group of suppliers, could undercut all other competitors. Similarly, collusive practices among suppliers can lead to restriction of supply in order to raise prices. Finally, lack of equal access to bottleneck facilities can restrict competitive entry and expansion. The first two of these factors are addressed by the antitrust laws, which can be invoked should such circumstances arise. The third factor, equal access to bottleneck facilities, is already dealt with in RG&E's tariff for gas transportation service. The Public Service Law itself also prohibits unduly discriminatory practices.[23] In addition, RG&E's settlement in the electric Competitive Opportunities Proceeding contains an extensive "Code of Conduct" governing relations among Company affiliates, as well as between the Company or its affiliates and third parties involved in the energy supply business.[24] The Code applies to gas, as well as to electric, operations.

These existing safeguards should be sufficient to protect the market from monopolistic abuse. Their effectiveness can be enhanced, however, by development of a "supplier manual" incorporating all relevant procedures and other information necessary for participation in the

[23] See Public Service Law § 65(3).

[24] Case 94-E-0952, In the Matter of Competitive Opportunities Regarding Electric Service and Case 96-E-0898, In the Matter of Rochester Gas and Electric Corporation's Plans for Electric Rate and Restructuring Pursuant to Opinion No. 96-12, Amended and Restated Settlement Agreement dated October 23, 1997, Schedule I. This Settlement Agreement was approved by the Commission in Opinion No. 98-1, Opinion and Order Adopting Terms of Settlement Subject to Conditions and Changes, issued January 14, 1998 in Case 96-E-0898.

market. As noted in Appendix A, RG&E has released the initial portions of its operating manual and further work will proceed as recommended by the Commission.[25]

If, notwithstanding the existence of the foregoing safeguards, a single supplier or group of suppliers is able to maintain higher prices than others for the same or similar products and retain substantial market share, such factors may be symptomatic of excessive market power that would require stronger remedial action.

RG&E recognizes that consistent policies regarding market power concerns are generally desirable; and the Company expects that there will be a generic resolution of these questions, as contemplated in the Policy Statement. At least for the proposed term of this rate and restructuring plan, however, the existing means of addressing any remaining concerns about market power should be adequate. The Company does propose a new market monitoring program, however. This is described in Section VI below.

2. COMMON ISSUES

a. Provider of Last Resort

In the Policy Statement, the Commission referred to provider of last resort ("POLR") issues as requiring resolution "in conjunction with electric restructuring proceedings" (Policy Statement at 9). Shortly after the Policy Statement was issued, the consideration of POLR issues in the electric restructuring proceeding of Orange and Rockland Utilities, Inc. ("O&R")[26] was expanded by soliciting input from other interested parties, particularly those involved in the gas industry, on Staff's position in that proceeding.[27] RG&E and other parties having an interest in POLR issues as they affect the gas business submitted comments and participated in discussions

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25 See Case 97-G-1380, Order Concerning Reliability, issued December 21, 1999.

26 Case 96-E-0900, In the Matter of Orange and Rockland Utilities, Inc.'s Plans for Electric Rate/Restructuring Pursuant to Opinion No. 96-12 (Unbundled Rates).

27 Staff's letter inviting participation was dated November 9, 1998, six days after issuance of the Policy Statement.

among the parties. To date there has been no resolution of the POLR issues presented in the O&R case[28] and RG&E assumes, for present purposes, that there will be no changes in the Company's current legal obligations with respect to this subject. That is not to say that POLR responsibilities must be handled as they are today. Indeed, the Company's plan provides for alternative means of carrying out these responsibilities in a manner consistent with the Commission's current vision. In the event that further guidance on POLR issues should become available during the course of negotiations, RG&E is prepared to address POLR responsibilities in light of such developments.

b. Other Common Gas/Electric Issues

The Commission also identified, for treatment in conjunction with the electric proceedings, "a plan to allow competition in . . . areas, such as metering, billing, and information services" (ibid.). To date, no determination has been made with respect to these issues. Accordingly, RG&E has not assumed any change in responsibilities with regard to these activities. In the event that a determination requiring a change in treatment should occur during the negotiations, the Company will address any such change at that time.

E. IMPLEMENTATION ISSUES

While the major points of the Commission's vision for the future of the natural gas industry are clearly stated, the vision raises numerous practical issues that must be resolved in order to proceed. In this Part, we describe these issues and the Company's related conclusions. We have grouped the issues under the four elements of the Commission's vision that apply directly to the upcoming Company-specific restructuring negotiations.

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28 Separate from the O&R case, however, Staff has undertaken a series of meetings with individual stakeholders to obtain their views on a variety of issues pertaining to the transition to competition, including the handling of low-income customers and other customers who are not attractive to competitive marketers, at least under existing conditions. Staff's report, entitled "Stakeholders' Views on Competition: from Transition to the End State," was issued on the Commission's web site on or about December 23, 1999 (http://www.dps.state.ny.us/stakeholder.htm).

1. COMPETITION AND CUSTOMER CHOICE

The Commission envisions that LDCs should cease selling gas, leading to the establishment of a "competitive market in gas supply." Additionally, the Commission believes that "the regulation of a competitive function should be unnecessary" (Policy Statement at 4).

The current situation, of course, is rather different from the end-state proposed by the Commission. In particular, most of the natural gas consumed in New York State is sold by the regulated utilities at regulated prices. In RG&E's case, in 1999, 62 percent of system throughput was sold through the regulated business. Due to the great disparity between current circumstances and the Commission's vision, legal, economic and contractual issues must be addressed and resolved before that vision can be implemented.

Proposals to move toward the Commission's vision must first acknowledge and accommodate the existing legal framework applicable to LDCs. New York's utilities are governed in part by the terms of the Transportation Corporations Law ("TCL") and the Public Service Law ("PSL"), which includes the Home Energy Fair Practices Act ("HEFPA"). Franchise agreements also impose certain obligations on the utilities. These laws, and most franchise agreements, were drafted with no expectation of unbundling or the introduction of competition; therefore it is unclear how their requirements will be interpreted in light of the Commission's vision. However, the basic obligations of the utilities appear to be as follows. First, the TCL appears to require the LDC to provide gas service to all non-residential customers who request it. HEFPA may require the same for residential customers, and it adds a number of provisions governing minimum terms and conditions of service for that class of customers. Utility franchise agreements, arguably, also require the provision of service for all customers who meet the requirements for such service. Finally, the PSL requires that utility rates be just and reasonable, and that rates may not discriminate against similarly situated customers.[29]

The basic question that needs to be answered is this: Is price deregulation consistent with the law? The answer to this question requires an affirmative response to each of two sub-questions. First, can the cost of the merchant function (principally the gas commodity and upstream capacity portion) be separated from that of the LDC function and subjected to the market? The answer, subject to the uncertainty of interpretation discussed above, appears to be yes. There appears to be no statutory impediment to this course. The second sub-question is, can the LDC's traditional role with respect to the merchant function be "delegated" to other suppliers? Again, subject to the aforementioned uncertainty, the answer seems to be yes. These two inquiries rejoin under the concept of the LDC's obligation to serve. For the present, at least, it would appear that, while the LDC retains responsibility to ensure that commodity services are available to customers within its service territory, the Commission has substantial flexibility, under the applicable law, to determine how that responsibility is carried out.

A second set of issues flows from simple economic analysis of possible transition scenarios where a competitive retail market for the natural gas commodity exists alongside a regulated market for the same product. This situation would produce significant financial risk for both regulated and competitive suppliers. Consider a situation where customers may switch without limit between regulated and competitive suppliers. Competitive natural gas prices are volatile, whereas regulatory pricing rules tend to dampen the impacts of that volatility on

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[29] It is important to recognize that RG&E does not present the foregoing interpretations as definitive, indisputable constructions of the relevant statutes, case law or franchise obligations. Instead we present these plausible interpretations to underscore two points. First, implementation of plans that are consistent with the Commission's vision may face obstacles in the form of legal requirements established in another era. Second, proposals to move toward the Commission's vision must take into account the utility's fundamental obligations under the law.

regulated rates.[30] Occasionally, then, adverse market price changes will produce situations where regulated commodity prices are below prices available from competitive suppliers, causing customers to flock from competitive suppliers to the regulated merchant. In particularly extreme circumstances, regulatory authorities could come under political pressure to prevent regulated prices from fully reflecting increased costs. The resulting artificial price signals would negatively impact competitive suppliers, since they would lose their customers. Those suppliers without the financial wherewithal to struggle through the dry spell would be forced to withdraw from the market. The situation would adversely affect the regulated supplier as well, became it could be forced to absorb the increased costs. In RG&E's case, for example, a 10 percent increase in the city gate cost of gas, if unrecovered, would increase system-wide annual costs by $15 million to $20 million and result in losses for the gas segment of RG&E's business of $5 million to $10 million over the course of a year.[31] This analysis demonstrates that movement toward the Commission's vision of full deregulation of retail prices should be as rapid as possible in order to quickly eliminate the risks described above.

A third set of issues is related to long-term contracts to which the utilities are parties and which enable the utilities to meet their basic service obligations. The State's utilities hold long-term firm capacity contracts on the upstream pipelines that serve their systems. These contracts allow for the movement of system supply gas from producing areas to LDC city gates, and for the seasonal storage of gas supplies. The details regarding RG&E's capacity contracts are

30 RG&E's existing gas cost adjustment rules spread price fluctuations over a twelve-month period.

31 It should be noted that a regulated price offer has coexisted with a fully competitive market for gas commodity for the large-volume customer segment since transportation gas was initiated in the mid-1980s, and the concerns raised above have not been manifest. This is because customers in this segment have not been required generally to contract for firm capacity at RG&E's city gate, so the effective difference between regulated and competitive prices has been sufficient to fully overshadow market price volatility. In order to ensure continued reliability of supply in the small-volume market, Commission rules require suppliers to such customers to have firm capacity at the LDC city gate for a portion of the year, so the effective price difference is not as great. See Case 97-G-1380, Order Concerning Assignment of Capacity, issued March 24, 1999, and subsequent orders in the same proceeding.

described fully in Section II of this filing and in the Updated Report (Appendix C hereto). These arrangements support highly reliable supply for customers taking service at regulated rates. However, current market prices for this utility-owned capacity are generally less than the regulated prices that the utility must pay to the pipelines under long-term agreements. As a result, when customers migrate to competitive suppliers, utilities are not able to recover 100 percent of the capacity costs they incurred to serve those customers. The difference between the costs that the utility is obligated to pay and the market price of the capacity is generally described as "transition costs." The utilities must be allowed to recover these transition costs so that they are not punished, in effect, for their historical obligation to serve as the retail merchant. At the same time, cost recovery must be designed in a way that treats all customers in an equitable manner.

2. PROVIDER OF LAST RESORT

The Commission intends for the regulated utilities to "continue to be the provider of last resort for gas service, at least for the short term . . ." (Policy Statement at 5). Clearly, the Commission's vision on this score is consistent with the LDCs' apparent statutory obligations under the law, as described above. Specifically, LDCs appear to have a statutory obligation to ensure that service is available within their territories, at just, reasonable and non-discriminatory rates. For residential customers, certain minimum terms and conditions must be made available. It also appears that the Commission has substantial flexibility in ensuring that these obligations are met.

3. RELIABILITY

The Commission articulated its firm view in the Policy Statement that "[n]o compromise in system reliability will be permitted." In order to achieve that result, the Commission stated its intention to allow LDCs to "maintain access to sufficient assets . . . to assure proper operation of the system" and to "impose reasonable requirements on marketers to assure such proper operation" (Policy Statement at 5, 6). Currently, RG&E's system supply and reliability management operations are closely intertwined. As a result, the maintenance of adequate supplies is critical to RG&E's ability to operate its system reliably. The system supply function provides the foundation for managing system reliability in four critical dimensions: (1) managing daily flows into the system; (2) managing hourly flows into the system; (3) managing flows by delivery point; and (4) ensuring reliable deliveries. These dimensions of reliability are described below.

a. Managing Daily Flows

RG&E must operate its system to ensure that daily deliveries follow daily load variations. The Company meets these requirements through a combination of managing daily system supply deliveries (utilizing both flowing supplies and storage) and through no-notice storage. Both nominated and no-notice services are critical to the successful management of deliveries. Two examples illustrate this point.

First, consider a winter day. The utility first forecasts total system load for a given day. It subtracts planned deliveries from competitive suppliers to determine the amount for which it is responsible. The utility then determines the amount of gas it would ideally take from no-notice storage on that day, and nominates volumes under its flowing supply and firm storage contracts to make up the remaining forecast volume. RG&E's flowing supply contracts fall into two categories: base load supply and swing supply. Base load supply nominations generally do not vary from day to day. Swing supply nominations do vary to meet varying demands. On the actual day of flow, more or less gas will flow from no-notice storage, depending on how actual load differs from the forecast load. The original plan for the day, of course, must be set to ensure that no-notice withdrawals stay within the boundaries of the utility's contract with the no-notice storage provider. These boundaries ordinarily change as the season progresses. Occasionally, intra-day nominations may be necessary to stay within these boundaries, or to fine-tune flows from storage.

Next, consider a summer day. Again, the process begins with a forecast of load for the day. The utility then subtracts planned deliveries from competitive suppliers and adds planned injections into firm and no-notice storage. On the actual day of flow, more or less gas will flow into no-notice storage, again depending upon the difference between forecast and actual system demand. The utility must make its original plans so that flows into storage comply with its storage contract; and again, contractual limits ordinarily change as the season progresses. The utility may make intra-day nominations in some cases in order to stay within limits or to fine-tune flows.

These examples illustrate that both nominated supplies and no-notice storage are used to meet fluctuations in demand. Nominated supplies are varied to meet forecast loads; no-notice supplies allow management of unplanned variances from the forecast; intra-day nominations provide a tool for quick response to unexpected variations in load.

Daily swings between transportation gas deliveries and consumption add to the total daily swings that RG&E must manage. For aggregation loads, suppliers generally provide a flat monthly amount equal to the expected average daily consumption of their customer groups during each month. For large-volume loads, suppliers may choose between two options. The first involves managing their own deliveries so that daily deliveries follow daily loads. No suppliers have chosen this option to date. The second option involves accepting a daily delivery quantity from RG&E. Under this approach, RG&E has the option to change the daily delivery quantity in order to keep the difference between deliveries and consumption within certain limits.[32] In any event, the utility has the responsibility to manage daily swings for both retail and transportation load.

A necessary precondition for the use of swing supply contracts and no-notice storage to manage daily system loads is the existence of a utility merchant function. Without retail sales customers, and thus without the supply and capacity resources associated with the merchant function, RG&E's management of daily swings would be greatly complicated. For example, if actual load exceeded forecast load, the utility would have to bring in gas and recover the cost from competitive suppliers. Such a process could lead to arguments over which supplier was responsible for how much of the additional gas and over how much the gas cost or should have cost. In the opposite situation, where actual flows were less than forecast load, the utility would have to buy gas somewhere upstream of the city gate and get rid of it somehow. This could lead to arguments over how much gas the utility should buy, from which supplier it should buy and how much it should pay. Clearly, the system works efficiently today because the utility's merchant role allows it to increase or decrease deliveries for its own load so as to follow increases and decreases in total system load.

Note that the use of no-notice storage alone to manage daily load fluctuations would be extremely expensive. If RG&E were to depend upon that type of resource only, it would have to maintain adequate injection and withdrawal capability to meet the maximum expected difference, positive or negative, between average daily flows and peak and minimum daily flows throughout the year. Such a strategy would increase RG&E's no-notice storage costs dramatically.

32 To date, the Company has not exercised its full rights under the tariff to manage deliveries to the allowed tolerances.

b. Managing Hourly Flows

Managing hourly flows into the system is the second critical dimension of system reliability. RG&E's system load varies hour by hour. For example, the minimum hourly flow can be less than 3 percent of the daily flow. The maximum hourly flow can be almost 7 percent of daily flows. The typical hourly load profile varies with the magnitude of the demand placed upon the system. During high load conditions, when spaceheating equipment makes up a huge share of the load, the hourly profile is generally flatter than during low- to medium-load conditions when process use makes up a larger share of the load.

RG&E depends upon the upstream pipelines serving the system to meet hourly variations in load. This is because RG&E has no on-system storage capability, and little ability to use "line-pack" for this purpose. Pipeline operating constraints vary. For instance, the Empire State Pipeline, one of two pipelines serving the Company, restricts hourly flows to a maximum of 5 percent of daily flows except when greater amounts are specifically authorized. Currently, no such limits exist on the CNGT system, the other pipeline to which the Company is connected; so hourly load variations in excess of 5 percent are generally provided for through deliveries on that system[33]. The key point is that, at present, RG&E holds city gate capacity contracts that support hourly load variations on its system.

Of course, RG&E holds these contracts in order to fulfill its merchant obligations. As this role shrinks in accordance with the Commission's vision, the Company's contract holdings will – ideally – also shrink. In that environment, competitive suppliers serving the system will have to take on contracts that support hourly load variations.

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[33] CNGT has recently proposed hourly flow limits for firm transportation service. This could require the Company to change its operating procedures.

c. Managing Flows by Delivery Point

Delivery point constraints are the third dimension of system reliability. In RG&E's case, the Rochester district, which makes up the bulk of the system, is supplied through two city gates. The Caledonia city gate is the Company's connection to the CNGT system. The Mendon city gate connects RG&E with Empire. Together, these two city gates serve 95 percent of the system load. In addition, a back-up connection with CNGT exists at Tyre, although this city gate is rarely used. Service of the Pavilion district represents roughly 5 percent of total system load; this district is not physically connected with the rest of RG&E's distribution system and is served through a number of connections with CNGT.

As more fully described in Appendix J, neither the Caledonia nor the Mendon city gate is individually capable of supplying peak loads in the Rochester district. Both are needed to serve the system reliably. The degree to which the system can depend upon one city gate or the other varies with load conditions. In general, higher loads mean that a smaller percentage of system demand can be served through Mendon, and, during peak load conditions, supplies must flow through both city gates. Prior to November 1999, the Company managed these constraints with no interaction with competitive suppliers. Recognizing that transportation gas loads had grown to the point where that approach was becoming increasingly risky and potentially costly, in November, 1999, the Company instituted a seasonal planning process and proposed a surcharge to share the burden of managing delivery point constraints with marketers. The surcharge is currently under consideration by the Commission.[34] The seasonal planning process is in place.

34 Case 99-G-1468, Ordinary Tariff Filing of Rochester Gas and Electric Corporation to Implement a Seasonal Planning Process Ensure System Reliability. The Company made its initial filing on October 22, 1999. On November 16, 1999, RG&E agreed to postpone its implementation.

In any event, even the newly implemented process calls for the Company to shift its system supply gas from one gate to the other if daily operating conditions so require. Obviously, this system will not work if the Company has no system supply obligations. As the Company's merchant role shrinks, competitive suppliers must become responsible for meeting delivery point constraints.

d. Ensuring Reliable Deliveries

The fourth dimension of reliability is ensuring reliable deliveries. RG&E's system load is used primarily for spaceheating purposes. About 75 percent of retail throughput flows to residential spaceheating customers on an annual basis. Much of the remaining retail throughput, and a substantial share of transportation throughput, is used for spaceheating purposes as well. The Company serves very few dual fuel customers and serves no explicitly interruptible load. Curtailment, of course, would be an extremely undesirable event, both due to the cost, inconvenience and hazards associated with interruption of gas service, and due to the cost of restarting the system after the event. Therefore, reliability of upstream supply is critically important. Given current regional load patterns, peak loads occur in the winter and planning for the winter peak is of the highest priority. In the future, if current plans come to fruition, a substantial amount of gas-fired generating capacity will be in place in the State and summer capacity planning could become equally critical.

RG&E provides for a continuously reliable supply of gas through its firm contracts with upstream pipelines and firm gas supply contracts. The PSC recently adopted a requirement that marketers serving aggregation and human needs load within the state contract for sufficient firm, primary city gate capacity during five winter months to meet the peak requirements of load they serve.[35] No matter what the future holds in terms of load patterns, if RG&E is to exit the

[35] See footnote 32, supra.

regulated merchant function, competitive suppliers must take on the responsibility for continuously serving firm loads.

e. Conclusions Concerning Reliability

In order to manage each of the four dimensions of reliability described above, RG&E makes use of assets and capabilities directly associated with its role as a gas commodity merchant. If RG&E is to shed that role, an entirely different regime for managing deliveries of gas into the system will be necessary in order to maintain reliability. The Company believes that new procedures should be implemented as soon as possible, so as to provide an adequate testing period for the refinement of new systems and approaches. RG&E's proposals for phasing in the necessary changes are presented later in this document.

4. CUSTOMER EDUCATION

The Commission has concluded that "[e]nhanced customer education is needed to facilitate the transition to a competitive market." The Policy Statement goes on to state that "LDCs must provide customer education as long as they are in the merchant business" (Policy Statement at 6.)

RG&E has long been active in educating customers about all aspects of its business, including the retail access program. With respect to natural gas choice, large-volume gas customers were given the opportunity to choose suppliers starting in 1985, and by 1996 virtually all eligible customers had chosen to switch. Customer education during this period was supported by one-on-one contacts between eligible customers and their RG&E marketing representatives and was driven by the marketing efforts of the unregulated gas suppliers. Retail choice was made available for all gas customers beginning in November, 1996,[36] and the Company's information programs entered a new phase at that time. The Company prepared a

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[36] Migration to the small-volume transportation program was limited to specified consumption caps, but all customer classes were eligible to participate.

generic gas choice booklet in cooperation with Staff and delivered it to all RG&E gas customers. The Company prepared and distributed supporting news announcements, bill inserts, and Solutions Page articles.[37] The Commission approved changes to RG&E's large-volume transportation program at the same time, and the Company invited all affected customers to attend one of a series of orientation sessions dedicated to describing new program features. The Company held orientation sessions for marketers as well prior to the implementation of the program changes.

Retail choice for electric service began in February 1998 with the introduction of the "Dairylea" retail access pilot program and expanded in July 1998 with the introduction of RG&E's full-scale program. Prior to implementation, the Company undertook many of the same informational activities that it utilized to educate the public regarding gas retail choice: news announcements, bill inserts and Solutions Page articles. To supplement these activities and place the introduction of choice in the larger context of industry restructuring, RG&E produced two detailed videos that were used in public presentations and aired on public access television[38] and carried out a television and radio advertising campaign. In addition, the Company carried out two orientation sessions for potential energy service retailers in which it described the operational details of the program. To date, the Company, through the Community Relations team, has conducted nearly 150 community presentations in response to public interest in obtaining information about choice. In addition, choice is included in the Company's overall portfolio of presentation topics. RG&E has also developed an E-Choice Fact Kit. It is mailed

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37 The Solutions Page is a full-page, paid advertisement that appears monthly in local newspapers. The Solutions Page provides information about services and programs that the Company offers. The Company also publishes a Spanish-language version, knows as *Soluciones*.

38 One of the videos was produced before the Competitive Opportunities Settlement (in Case 96-E-0898, In the Matter of Rochester Gas and Electric Corporation's Plans for Electric Rate/Restructuring Pursuant to Opinion No. 96-12) was signed in 1997 and, therefore, focused on the fundamental issues that led to industry restructuring efforts.

directly to customers who call for information regarding retail choice, and it is also available via the Company's web site.

The results of these efforts have been impressive. RG&E's recent retail customer surveys included questions related to awareness of competitive retail service. The most recent results, from November 1999, show that 78 percent of residential customers in our service territory say they have seen or heard about electric energy choice from RG&E. That is up from the 58 percent awareness number found in the summer survey just six months earlier. Of those who have heard about it, nearly 40 percent say they understand choice clearly, based on what they have heard from RG&E.

The same questions were asked in the survey with regard to awareness of gas choice. In the November 1999 survey, 67 percent said they were aware of gas choice. That is up from 52 percent in the survey conducted just six months earlier. These increases are attributable chiefly to an intensified paid advertising campaign in the fourth quarter of 1999, where one 60-second radio spot and two 30-second TV spots were run. This conclusion is further supported by the survey result that showed that residential customer recall of seeing and hearing any RG&E advertising went from 47 percent in the summer to 57 percent in late 1999.

Clearly, RG&E's customer education efforts to date have been effective in preparing customers for the advent of retail access. Specific proposals to add to these efforts are described later in this document.

F. GOALS

Before embarking upon a description of RG&E's proposals, it is appropriate to describe the goals that the Company considered while crafting its plans. Obviously, the primary goal is to comply with the Commission's Policy Statement. Given the vision articulated in that document, the Company has used the following specific goals and constraints as a guide.

1. ***End retail price regulation as comprehensively, quickly and thoroughly as possible.*** This is clearly the primary outcome sought by the Commission. And, for the reasons set forth above, a mixed system of regulated pricing alongside a competitive, unregulated market is untenable in the long run. Quick action to progress as far as possible toward the end state is clearly the best approach.

2. ***Maintain system safety and reliability.*** While the Commission's Policy Statement clearly seeks change in some fundamental aspects of the gas business, it is equally clear in demanding that no degradation of safety or reliability be allowed to occur.

3. ***Keep regulated rates as low as possible, consistent with maintaining the utility's ability to provide safe and reliable service and to attract capital.*** The Policy Statement requires utilities to submit a rate plan with their restructuring plan. As it always has, the Company seeks to serve its community as efficiently as possible and with the highest possible levels of service quality.

As further guidance in the development of its proposals, the Company has adhered to the following principles.

1. ***Eliminate subsidies between customer groups where possible, and do not create new subsidies.*** This is a long-standing and well-accepted regulatory priority, and the Company has found that even short-term deviations from this principle can lead to recalcitrant problems later on.

2. ***Ensure that the end result provides RG&E with an opportunity to profit from the energy business in which it has participated for over 150 years.*** This clearly is consistent with RG&E's business strategy. Adherence to this principle also will provide for a stable long-term solution to the problems of transitioning to a more competitive marketplace.

3. ***Limit the proposal to just those items identified as necessary by the Commission.***. Clearly, the Commission has set before RG&E and the other interested parties a daunting and complex task: that of overhauling a business that has functioned as a vertically integrated regulated monopoly for most of the past century. Expanding the scope of the task beyond those boundaries will at least delay the achievement of the Commission's vision, and may prevent the achievement of that vision at all. The Company believes that a singular focus on the issues identified by the Commission as necessary to achieve its aims is by far the best way to reach a successful result.

G. SUMMARY OF PROPOSALS

In this Part, the Company presents a brief summary of its proposals. These are fully described in the following Sections of this document. In addition, for the convenience of interested parties, Appendix B contains a summary matrix describing this material. The Company notes that its proposals are intended to be a starting point for negotiations. RG&E is willing to work with good-faith counter-proposals from all interested parties. The Company further notes that many details remain to be worked out prior to implementation of some aspects of this proposal. The Company believes that such detail will be developed most effectively through an exchange of ideas in good-faith negotiations.

Section II and Appendix C present the Company's proposals regarding minimizing new capacity contracts and mitigating and managing potential stranded capacity costs. The Section describes the Company's current portfolio, quantifies the value of that portfolio, and presents the Company's long-term strategy for supporting the transition to a competitive retail market. As set forth below, RG&E finds that the ideal state would be one in which it reduces – and, if possible, eliminates – capacity commitments upstream of the city gate, and purchases all gas required for system supply at the city gate. This approach minimizes the risk of future stranded capacity costs. The proposed strategy to bring about this state is comprised of three prongs, each of which is under way. First, the Company has begun negotiations with the pipelines that provide transportation and storage services to it, with a view towards reducing costs and capacity commitments in a mutually agreeable manner. Second, the Company has initiated an "open season," offering its current capacity holdings to interested parties. Bidders are free to express interest in all or any subset of the Company's holdings. Third, the Company has issued a Request for Proposals for the packaging of supply and capacity into a market service for the Company's retail load. Successful bidders would take assignment of a share of the Company's remaining capacity holdings proportional to the retail load they agree to serve. Compensation would be in the form of dollars paid for gas delivered at the city gate. Section II and Appendix C present a complete description of each prong and provides an update regarding the current status of activities for each.

Section III presents the Company's rate plan. This plan is based upon data available immediately prior to the preparation of this document; limited updates may be provided later during negotiations. In general, as presented in Section III and in Appendix D, the Company expects revenues to be inadequate over the forecast period (July, 2000 through June, 2002) to provide an acceptable rate of return on equity. Appendix E provides the Company's analysis of the required return on equity. The Company proposes to address appropriate rate levels in the context of the upcoming negotiations, where the inter-relationship of all aspects of the proposal will be balanced. To the extent that an agreement reached in this proceeding commits the Company to increase expenditures on any aspect of its regulated gas business, it will seek additional revenues to fund those cost increases. The Company further proposes to adopt for the gas business mandate and catastrophic event protection similar to that adopted in the Company's electric Competitive Opportunities Settlement.

Section IV presents a plan to further unbundle rates. It describes a three- to five-year rate design strategy and provides specific proposals to initiate implementation of that strategy. Specifically, the Company seeks to increase monthly minimum charges, roll gas costs out of base rates, and revise the gas adjustment clause in limited ways consistent with the Commission's latest Order on the subject. The Company proposes to continue to recover transition costs as it does currently, until such time as retail prices are fully deregulated. At that time, the Company proposes to switch to a uniform surcharge on all post-November 1, 1996 transportation load. This surcharge would be designed to recover all remaining capacity costs over a reasonable period of time, and would cease when those costs are fully recovered. The Company does not propose a specific retailing backout credit at this time, recognizing that the level of the credit must depend upon agreements reached with respect to the nature of the retail access program and the future of regulated commodity service. The Company also proposes to adjust balancing charges in a manner consistent with its proposals for improved balancing services. The level of those charges cannot be calculated at the present time, however, due to the unresolved status of CNGT's filing with the Federal Energy Regulatory Commission ("FERC") to implement new services for marketers serving retail loads. Appendix F presents customer bill impacts. Appendix G provides a marginal customer cost study relevant to the Company's proposal to revise the monthly minimum charges. The Company plans to supplement this filing with a revised embedded gas cost study as well.

Section V presents the Company's customer education plan. It describes the goals motivating the design of the program, and presents related strategic guidelines. The Company proposes to continue to measure customer awareness of gas choice, as well as understanding of gas choice, and to use the results of this measurement program to evaluate the effectiveness of its customer education efforts. The Company proposes to utilize customer focus groups and RG&E/marketer forums to guide the development of content for the education program, and to utilize a variety of tested and proven delivery methods. RG&E also proposes to submit to Staff an annual customer education report to be developed in cooperation with marketers operating in the Company's service territory.

Section VI presents the Company's proposals to facilitate the development of a competitive market. It is divided into five subdivisions. The first deals with the nature of distribution service. It describes the differences between electric and gas distribution service, and differences in services provided to large-volume and small-volume gas customers. While the Company believes that customers will be best served by the implementation of the single-retailer model for gas distribution service, it recognizes that the Commission is considering the issue on a generic basis through its inquiry on retail access billing practices.[39] Rather than make a proposal in this proceeding which may conflict with a generic ruling later on, and in order to avoid introducing an additional level of complexity into the forthcoming negotiations, the Company will not propose to implement the single retailer model at this time. However, the

[39] Case 99-M-0631, In the Matter of Customer Billing Arrangements.

Company does propose to address certain flaws and inconsistencies in its current transportation gas tariff. In summary, the Company proposes to create an explicit tariff-based relationship between all competitive suppliers and the Company. The Company further proposes that balancing charges be imposed on suppliers and not on retail customers, and that operating details be moved to a supplier operating manual. The proposed changes are described below and summarized in matrix form in Appendix H.

The second subdivision of Section VI deals with the management of transportation gas deliveries to RG&E's system. As noted above, a new regime for managing deliveries is necessary to allow for the LDC to exit the merchant function. RG&E's proposed end state would require that competitive suppliers forecast their own load for each gas day, make intra-day nominations as necessary to ensure that system integrity is maintained in the face of unexpected load changes, participate in a seasonal planning process to ensure that delivery point requirements are met, ensure that nominations are within limits for each delivery point on a daily basis, arrange for delivery contracts that support expected hourly load variations for their customer groups, and contract for CNGT's CSC service or its equivalent in order to manage daily load variations. RG&E's proposals to phase in this new regime are presented below, and in summary form in Appendix I. Appendix J provides details regarding delivery point constraints.

The third subdivision of Section VI presents RG&E's proposals regarding its interactions with gas marketers supplying load on its system. The Commission recently issued the "Reliability Communications Working Group Report" in Case 97-G-1380, and encouraged the utilities to adopt communications protocols dealing with the issues identified in that report. The Company has developed a proposed communications protocol; it is included as Appendix K and is described below. In addition, the Commission has ordered the utilities to develop and distribute supplier operating manuals, governing the day-to-day operating practices necessary for successful retail access programs. The Company has already promulgated the initial sections of its operating manual, as described in Appendix A.

The fourth subdivision of Section VI provides the Company's proposal for full deregulation of retail commodity prices. Of course, the Company's rates for transportation service would continue to be regulated as they are today. The Company proposes a target date of May 2002, for deregulation of retail prices for all customer segments, assuming that the end state for managing deliveries of gas into the system will not be implemented prior to that time. The Company proposes to structurally separate its retailing functions from its distribution function at that time, and to apply at that time the standards of conduct pertaining to affiliate relationships adopted by the Commission in the Competitive Opportunities Settlement. RG&E proposes that upstream assets that have not been shed as a result of the capacity cost mitigation plan presented in Section II and Appendix C continue to be the responsibility of the regulated distribution company. Its affiliate will be treated like any other competitive supplier for the purposes of capacity release or other sales of capacity. The Company proposes, in addition, that a market monitoring plan be adopted by the Commission, and that the Commission further adopt certain procedures for resolving complaints regarding alleged exercise of market power.

The fifth subdivision of Section VI presents the Company's proposals with respect to its obligation to provide service. Regarding residential service, the Company proposes to solicit bids from qualified competitive suppliers to provide services to all who request it under the terms and conditions of the applicable law. The supplier would charge the customers it serves fixed or indexed rates for unbundled services, and the Company would contribute an additional amount to cover the incremental costs related to that service. The Company would collect the subsidy amount through rates for distribution service. Regarding non-residential service, the Company proposes to solicit bids from qualified suppliers that are willing to provide commodity service to such customers. Bidders would be free to propose reasonable customer segments, within which pricing would be uniform. Bidders would also be free to propose other uniformly applied, reasonable terms and conditions of service. In this case, the bidders would depend entirely on revenues from their retail customers; the Company would provide no additional funds. While not required by the law, the Company proposes to continue its existing low-income assistance program, with some improvements. The cost of the program would be collected through a surcharge on all throughput. Appendix L provides details regarding this program.

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SECTION

II

CAPACITY COST MITIGATION

The first two of the six substantive issues required to be addressed in filings pursuant to the Policy Statement pertain to the control of capacity costs: a "strategy to hold new capacity contracts to a minimum"; and a "quantification of potential stranded costs and a plan to mitigate and manage them" (Policy Statement at 8). The avoidance of new contractual obligations for upstream capacity, a determination of the Company's potential exposure to stranded costs, and a strategy to mitigate and manage such costs were at the heart of the Capacity Report submitted to Staff on November 29, 1999. That Report constitutes an in-depth review of RG&E's entire capacity situation and, as such, provides greater detail on this subject than otherwise would appear to be required by the Policy Statement. In complying with the requirements set forth in the Proposal, however, RG&E considered such depth important to a full appreciation of the Company's unique circumstances. Likewise, the Company contemplated that the update to the Capacity Report to be included in this filing would provide a similar level of detail as to RG&E's capacity circumstances.

Accordingly, to fulfill the requirements of the Policy Statement and the Proposal, RG&E is including, as Appendix C to this filing, the updated version of the Capacity Report (the "Updated Report"). In addition to updating the information provided to Staff in the original November 29, 1999 Report and the two supplements thereto, the text of the Updated Report has been modified to remove commercially sensitive information contained in the initial version that necessitated treatment of the original and supplemental submissions as trade secrets under the Commission's regulations.[1]

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[1] See 16 NYCRR §§ 6-1.3, 6-1.4.

Although RG&E is cognizant of the desire of the Commission and various parties to make public as much information as possible on this subject, it is important that sensitive commercial terms and strategies ultimately intended to operate to the benefit of customers not be compromised by disclosure. The need for trade secret treatment is all the more critical in these circumstances where RG&E is actively engaged in seeking to market surplus capacity and to negotiate with pipelines.[2]

As Staff is already aware, and as first-time readers of the Updated Report will readily become aware, RG&E is continuously pursuing the strategies and actions identified in that Report. Accordingly, the Company anticipates providing further updates to this Report as significant developments occur, just as the Company did in the two Supplements that followed the November 29, 1999 initial submission.

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2 One further point regarding confidentiality warrants mention. The original and updated versions of the Capacity Report refer to and append excerpts from the March 4, 1999 Upstream Capacity Study that the Company presented during settlement negotiations. As pointed out in the updated Report (see Report at 5, footnote 9), although RG&E has waived the confidentiality of the excerpts from the Upstream Capacity Study as a settlement document subject to the Commission's regulations governing settlements (16 NYCRR § 3.9), the Company does not waive the right to request trade secret status for the contents of the Capacity Study in accordance with the Commission's Trade Secret Regulations. (16 NYCRR §§ 6-103, 6-1.4)

SECTION

III

LONG TERM RATE PLAN

The Commission's Policy Statement requires that, in preparation for negotiations, LDCs address, among other things, a long term rate plan with a goal of reducing or freezing rates (Policy Statement at 8). As noted in Section I, the Company's rates for distribution service have been frozen for more than five and a half years.

A. REVENUE REQUIREMENTS

The Company has prepared and is presenting in this proposal a two-year rate plan. Appendix D reflects the development of revenue requirements for the forecasted rate years ending on June 30, 2001 and June 30, 2002, respectively. Appendix D has been prepared in a manner consistent with the "Commission Guidelines Regarding the Support for Rate Proposals and Unbundling Under the Gas Policy Statement" as attached to the Commission's Order Clarifying Gas Policy Statement, issued April 1, 1999 in Case 97-G-1380.

Appendix D consists of 7 pages and is organized a format similar to the Gas Income Statement and Rate of Return exhibits presented by the Company in prior regulatory filings as follows:

Pages 1 and 1a. Income Statement and Rate of Return
Page 2. Expenses
Page 3. Amortizations and Book Depreciation
Page 4. Taxes, Other than Income
Page 5. Federal Income Taxes
Page 6. Average Rate Base

Each of the aforementioned pages, which will be discussed later in this Section, is organized in a similar manner. Descriptions of the various line items are contained in the far-left column on each page, followed by columns displaying both adjustments and the forecasted rate year data. Moving from left to right, the first column, labeled "Test Year End Dec. 31, 1999" reflects the actual historical data for the twelve-month period ending on December 31, 1999. The next column displays adjustments that were made to normalize the historical test period. The column labeled "Proforma. Dec. 31, 1999" reflects the normalized December 1999 results.

The remaining columns display adjustments and rate year data for the forecasted rate years ending on June 30, 2001 and June 30, 2002, respectively. The rate years were developed under traditional cost of service rate making principles showing the revenue requirements necessary to produce a fair and reasonable rate of return for the Company's Gas Operations.

Descriptions of the adjustments reflected on the aforementioned pages are contained in the footnotes. Additional information, calculations and related documentation can be found in the Company's workpapers.

In addition to the footnotes describing the various adjustments contained in Appendix D, an overview of the major cost components follows to facilitate an understanding of the methodology employed to develop the revenue requirements.

1. REVENUE FORECAST

Consistent with past practice, the Gas Revenue Forecast was developed by using a multi-step process as follows:

a. For Retail and SC 5 Forecasted Sales

The forecasted rate year sales were developed by averaging two prior year actuals and normalizing those to the rate year's normal heating degree days ("HDD"). For example, the normal for December 2000 is 901 HDDs (based on the average number of consumption days for that billing period). Therefore, December 1997 and December 1998 actuals were averaged; then a baseload (the average of August 1997 and August 1999) was subtracted. The result is a heating load that is then divided by the actual heating degree days (the average of December 1997 and December 1998). This results in a heat load per HDD. This heat load per HDD is then multiplied by the normal HDD (901) for December 2000, resulting in the projected heat load for December 2000. The baseload is then added back to the heat load, resulting in the forecasted December 2000 load. This methodology was used for each month of the forecasted rate years.

b. For SC 3 Forecasted Sales

Rate year sales were forecasted using the actual metered loads recorded for October 1998 through September 1999. On a calendar month basis, baseload (the smallest throughput month for that 12 month period) is subtracted from the actual load for a given month, resulting in that month's heat load. This value is divided by the actual HDDs for that month resulting in a heat load per HDD value. The heat load per HDD value is multiplied by the normal HDDs for that calendar month and the baseload is added back. This results in the forecasted load for that month. Explicit adjustments were made for known changes in major customer loads.

c. Normalized Margins Per Therm Were Calculated By Restating The Actual 1999 Margins To Eliminate The Effect Of Weather. To Do This, The Following Steps Were Followed:

- Normalized 1999 sales were calculated, using the same methodology that was used for the forecasted rate year sales with the exception that actual 1999 sales were used (i.e., no prior year averaging was used).
- The average normal use per customer, by customer class, was calculated.
- The margin rate per therm from the rate block corresponding to the average normal consumption per bill for each customer class was applied to the sales variance (normal minus actual) to calculate the adjustment to the actual margin.

- The adjustment was added to the actual margin to calculate normalized margin.
- Normalized margins for the year divided by normal sales for the year results in the normalized margin per therm.
- This amount was applied to forecasted sales to develop forecasted margins.

d. Applicable Gas Cost Adjustment ("GCA") Rates, Transportation Rate Adjustments And Revenue Tax Rates Were Applied To Develop Rate Year Revenues.

All revenues are based upon current service classifications and current rates. Miscellaneous revenues are based upon the adjusted base period revenues and held constant throughout the forecast period. SC No. 2 – Gas Lighting Service revenues are included in miscellaneous revenues. The GCA mechanism reflects full recovery of purchased gas costs. Consistent with full recovery of purchased gas costs, deferred fuel expense is assumed to be zero in the forecasted rate years.

The supporting calculations and underlying assumptions are contained in the Company's workpapers.

2. EXPENSE FORECAST

Operation and Maintenance expenses, excluding fuel, were extracted, by cost category, from the General Ledger for the 12-month period ending on December 31, 1999. Common expenses for Class 5 (Customer Accounts Expenses) and Class 7 (Administrative and General Expenses) were allocated to gas operations by applying allocation factors of 48 and 35.6 percent respectively. Adjustments made to normalize the historic test period are contained in the footnotes to Appendix D.

Calendar Year 2000 operating expenses were developed from the Company's operating budget for that period. The basic steps in the preparation of the operating budget are as follows:

- Corporate guidelines for budget preparation were first distributed to department managers and their budget staff.
- The resulting departmental budgets were gathered and consolidated by corporate accounting staff.
- The consolidated budget was compared to corporate and business segment goals.
- Senior management reviewed the consolidated budget and decided on necessary changes.
- The resulting management-recommended budget was presented to the Board of Directors for its approval.
- Department managers and their budget staff compared the Board-approved budget to historic expenses by cost category, and identified normalization and activity-level changes.

Forecasted rate year expenses, for the most part, were then developed by applying projected GDP chained price escalation factors to the year 2000 operating forecast. Payroll expenses were developed by applying a 3 percent per year wage increment offset by a 1 percent per year productivity adjustment. Class 5 and Class 7 payroll expenses were allocated using allocation ratios from the historic test year.

Uncollectible expense was forecasted using a three-year average for the years 1996, 1997 and 1998. Pension credits are expected to be approximately $17 million in the year 2000. The forecasted rate year amounts for pension credits were developed by using a three-year average of 1998, 1999 and projected 2000 pension credits.

Fuel expense, labeled "Purchased Gas Cost" reflects the cost of existing upstream pipeline transportation and storage contracts and commodity pricing based upon a December 1999 NYMEX forward price forecast. A number of upstream transportation and storage service contracts are expected to expire during the forecast period. The forecast assumes that all upstream transportation and storage contracts that expire will be replaced with supplies purchased in the market-area or at the city gate, and that the Company will recontract for a portion of the CNG storage assets it currently holds.

3. AMORTIZATIONS AND BOOK DEPRECIATION

Base period amortization expense has been normalized to remove those items that will no longer be amortized subsequent to the end of the base period. The forecasted rate years reflect amortization expense for the recovery of costs relating to FASB 112, which will become fully amortized as of June 30, 2001, and the passback to customers of the gas portion of the proceeds received from the 1999 Contractor Settlement.

Book depreciation expense was developed using the newly developed composite accrual rates resulting from the Company's Depreciation Study. This study is included in the Company's workpapers.

The depreciation study consists of both an actuarial life study and a salvage study. The actuarial life study is a study of historical retirement experience and an evaluation of the applicability of this experience to future retirements. The actuarial life analysis addresses the determination of average service lives of each utility plant account.

The salvage study was based on historical gross salvage and cost of removal experience as it relates to the original cost of property retired. Data were analyzed by account to determine the gross salvage rate, cost of removal rate and net salvage rates.

Finally, an evaluation of the life analysis and salvage analysis as they relate to current utility property and future requirements was performed. This evaluation produced the applicable depreciation accrual rates for existing and future gas and common utility plant.

Composite depreciation accrual rates, retirement factors and net salvage factors developed in the Depreciation Study, along with the forecasted plant additions were used to determine book depreciation expense in the forecasted rate years. A further discussion of the calculations, as they relate to net utility plant, can be found later in this filing.

4. TAXES, OTHER THAN INCOME

The forecasted rate year Local, State and Other taxes were developed in the same manner and utilized the same escalation rates as operation and maintenance expenses. Consistent with payroll expense, a 1 percent productivity adjustment was applied to the forecasted rate year payroll taxes.

5. FEDERAL INCOME TAXES

Federal income tax expense was developed by applying the 35 percent Federal Income Tax rate to the pre-tax operating income resulting from the aforementioned items, giving recognition to the forecasted capital structure and other forecasted tax adjustments that have specific revenue requirement effects.

6. AVERAGE RATE BASE

Average rate base was developed by first determining Net Plant for each of the forecasted rate years. Net plant is the sum of the average balances for the various functional sub-groups which include Gas Production, Distribution and General and includes the portion of Common Structures, Transportation and Other that are allocated to the Company's Gas Operations.

Each of the aforementioned functional areas was developed individually starting with the beginning of period balances, as of December 31, 1999, for both plant and reserve. Retirement factors, composite depreciation accrual rates and net salvage factors from the Depreciation Study were used, along with the forecasted plant additions to project the impact on both plant and reserve balances. This methodology is consistent with that employed in the Company's prior regulatory filings and the supporting documentation can be found in the Company's workpapers.

With the exception of Gas Storage, which was forecasted separately, the Working Capital components were held flat at base period levels throughout the forecast period. Gas storage working capital reflects forecast storage inventory and commodity prices.

Finally, the actual and forecasted rate base reductions for deferred investment tax credits and deferred income taxes and amortization items have been reflected, where applicable, in a manner consistent with the income statement presentation.

7. COST OF CAPITAL

The calculation of each component of average capitalization and the associated cost of capital for each rate year, along with assumptions and supporting documentation, are located in the workpapers. Development of the average common equity for each rate year reflects the operations of RG&E and excludes the operations of any other subsidiaries of RGS Energy Group, Inc. The calculation of the indicated cost of capital for the rate year uses a common equity cost of 11.75 percent. This is the mid-range of the return on common equity as recommended by Robert Rosenberg in his report, "Report on the Determination of the Cost of Common Equity," which was prepared on the Company's behalf. This report is included as Appendix E.

The Company's proposed return on equity reflects the risks inherent in undertaking the transformation of its business proposed by the Commission. Implementation of the goals outlined in the Policy Statement will bring about fundamental changes in the way RG&E does business. These changes will create new risks. The Company must manage these changes and risks in a way that does not weaken the Company's financial performance, does not negatively impact the safety and reliability of the distribution system, maintains customer satisfaction and provides for a reasonable transition to a more competitive marketplace.

More specifically, the Company is faced with the following types of risks and uncertainties:

1. Traditional business risks will continue to exist, such as inflation, and economic cycles within the service territory, as well as within the broader economy. In particular, RG&E's service territory continues to be dependent upon the economic fortunes of specific, major employers such as the Eastman Kodak Company and Xerox Corporation.

2. RG&E must continue current reliability and maintenance programs, and perhaps even expand them, if necessary to ensure safety and reliability and meet all regulatory obligations.

3. The sheer complexity of the business process changes necessary to implement the Commission's vision creates a set of risks that can barely be imagined. Many fundamental operations managed by the Company will have to change to provide for a deregulated commodity market -- from billing, to provision of services as required under the law, to managing system reliability. Related Commission initiatives, such as its consideration of competitive metering, customer billing, uniform business practices, and electronic data interchange can raise costs in unexpected ways. While the Company proposes to defer and recover mandated costs and competition implementation costs as described below, it is probably impossible to create adequate protection given the complex and inter-related nature of possible changes.

B. REVENUE REQUIREMENT PROPOSAL

1. NEGOTIATION

Based on the revenue requirements analysis presented, the Company expects revenues to be insufficient during the forecast period to provide an acceptable return on equity. Specifically, the revenue requirements projection supports a revenue increase of $14.2 million (5.4 percent) for the rate year ending June 30, 2001, and a revenue increase of $4.0 million (1.6 percent) for the rate year ending June 30, 2002. The magnitude of a revenue increase will depend on the resolution of all the issues presented in this proposal. Therefore, the Company proposes to address appropriate rate levels through the course of negotiations, recognizing that revenue requirements are inextricably connected to every other aspect of this proposal.

2. MANDATE, CATASTROPHIC EVENT, COMPETITION IMPLEMENTATION COSTS

In the event one or more mandates[1] is implemented, or one or more catastrophic events[2] occurs during the term of this agreement, the Company proposes that the cost impact of any individual mandate or any individual catastrophic event be entitled to deferral treatment. That is, RG&E shall be entitled to defer the entire amount attributable to such mandates and catastrophic events and to recover or pass back such amount as soon as possible. In addition, the Company proposes to allow for deferral and recovery as soon as possible, the entire amounts associated with competition implementation costs.[3]

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[1] A "mandate" shall mean (a) any governmental action, including changes in laws and regulations (including tax laws and regulations) and orders of regulatory and other agencies which result in cost changes, and (b) any changes in accounting required by generally accepted accounting principles. In the event that any such "mandate" consists of actions in response to an asserted failure by the Company to conform to valid legal requirements, the Company shall have the burden of showing that its conduct which gave rise to such action was consistent with the best interests of customers.

[2] A "catastrophic event" shall mean an event that triggers the designation of part of the Company's service territory as a disaster area or as being under a state of emergency, or that results in curtailment of gas service to a portion of customers.

[3] "Competition implementation costs" shall mean all incremental expenditures, incurred by RG&E after an agreed-upon date, in connection with all regulatory proceedings, legislation, regulations, and orders pertaining to the development of a competitive market for natural gas service.

3. COST ADJUSTMENTS ARISING DURING NEGOTIATIONS

Should the parties reach agreement during the course of negotiations for RG&E to implement new programs, or enhance existing programs for which costs have not been included in the Company's filed revenue requirements, the Company proposes that the revenue requirements be adjusted to reflect such costs. Examples of programs where adjustments may be needed to reflect cost changes or enhancements as a result of negotiations are issues associated with POLR obligations, the low income program, the management of gas deliveries into the system, the development of balancing services, and the enhancement of customer outreach and education programs. To the extent that these costs cannot be quantified prior to the conclusion of negotiations and considered in the rate-setting process, the Company proposes to treat such costs as competition implementation costs as described above.

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SECTION

IV

PLAN TO FURTHER UNBUNDLE RATES

The Commission's Policy Statement requires that LDCs provide a "plan to further unbundle rates which would: (i) separate distribution costs and gas purchase (upstream) costs; (ii) separately identify distribution cost elements; (iii) identify changes which would promote retail competition; [and] (iv) propose other rate design changes, if appropriate" (Policy Statement at 8). The Company's proposal will address each of these.

A. STRATEGY

The Company's rate design strategy over the next three to five years is to address the Commission's goals as stated in the Policy Statement, and further to move to align rates with the cost to serve. To support the rate design proposals so as to achieve this goal of a greater correspondence between cost to serve and rates, the Company has included a marginal gas customer cost of service study in this filing, and is currently completing a revised embedded gas cost study. The marginal cost study is included as Appendix G. This analysis will provide support for revising the minimum customer charges. The results of the updated embedded cost study will be submitted upon completion. To the extent the results of the study support a reallocation of revenues among the rate classes listed below by Service Classification ("SC") number, the Company proposes to discuss this matter during the course of negotiations.

The rates for retail service will remain under SC 1 – General Service, SC 2 – Gas Lighting Service, and SC 4 – General Service – Economic Development. The rates for retail access service will remain under SC 3 – Firm Transportation of Customer Owned Gas, SC 5 – Comprehensive Transportation Service, and SC 6 – Supplier Service. SC 3 provides transportation gas service to large volume customers, whose annual usage is at least 50,000 therms. SC 5 provides transportation gas service to all general service customers. Companion services to SC 3 and SC 5, SC 7 – Banking Service and SC 8 – Storage Service, are expected to be eliminated during the term of this proposal.

The Company proposes to maintain the correspondence between the distribution, or delivery rates, net of the base cost of gas plus losses, of SC 1, SC 3 and SC 5. However, any change in revenue allocation, which will be carried out in the re-allocation of revenues among the rate blocks of these service classifications, will be supported by the revised embedded cost of service study.

B. RATE DESIGN PROPOSALS

The Company proposes the following rate design changes, to become effective on July 1, 2000.

1. SERVICE CLASSIFICATION NO. 1

a. Implementation of New Gas Cost Adjustment Regulations

On April 13, 1999, the Commission issued a Memorandum and Resolution Revising 16 NYCRR Section 280.55, the regulations governing the operation of the Gas Cost Adjustment ("GCA"). In a manner consistent with these new regulations, the Company proposes to roll out the base cost of gas, currently at $0.358 cents per therm plus losses, from all the rate levels for SC 1. This will completely separate the cost of gas (capacity and commodity) from distribution, or delivery rates. The total cost of gas will be collected through the GCA mechanism. The change will be reflected in the SC 1 bill, an example of which is included in Appendix F to this filing. There is no bill impact to the customer from implementing this change. The Company proposes making this change on November 1, 2000.

The Company also proposes to adopt other GCA changes as provided for in the Commission's April 13, 1999 Memorandum. Specifically, RG&E would adopt the following procedures: (i) inclusion of risk management costs in the GCA; (ii) calculation of the fixed cost component of the average cost of gas on the basis of weather normalized volumes; (iii) calculation of the commodity component of the average cost of gas on the basis of the estimated volumes for the month in which the GCA will be effective; (iv) reconciliation of the GCA at interim periods during the GCA reconciliation year in addition to the annual reconciliation; and (v) filing a revised GCA within five days of the effective date of an initial GCA filing when the replacement of estimated prices with actual prices results in a change in the average cost of gas of more than five percent. RG&E does not foresee any significant annual bill impacts to customers from implementing these changes.

b. Increasing the Customer Charge

The Company proposes to increase the monthly customer charge to $10. In order to moderate the bill impact of this change, the Company proposes to phase in this increase over the two-year term of this proposal. With gas costs rolled out of rates, the proposal is to increase the monthly charge by $2.10 in the first rate year, and by $2.09 in the second rate year. Therefore, the monthly charge will increase from the current $5.81, to $7.91 in the first rate year, and then to $10. Corresponding adjustments will be made to the rates in the subsequent rate block or blocks. An increase to the customer charge is supported by the results of the marginal customer cost study, which shows that the annual marginal customer-related cost to serve under SC 1 is at least $21. This cost study is included as Appendix G.

c. Redesign of Block Rates

At a minimum, the last two rate blocks of SC 1 will be eliminated. There is very little usage remaining in these blocks. With the elimination of these two blocks, total revenues collected from the SC 1 class will remain neutral for the Company.

2. SERVICE CLASSIFICATION NO. 3

In order to maintain the correspondence in rates with SC 1, the monthly charge for Firm Transportation Service, which applies to the first 1000 therms of use, is modified to $222.00 for the first rate year and $204.00 for the second rate year.

3. SERVICE CLASSIFICATION NO. 5

a. Increasing the Customer Charge

The minimum charge increase for SC 1 will also apply to SC 5. The monthly charge will increase from the current $5.81, to $7.91 in the first rate year, and then to $10 in the second rate year.

b. Redesign of Block Rates

The changes made to the block structure of SC 1 will also be made to the block structure of SC 5.

4. SERVICE CLASSIFICATION NO. 2 and SERVICE CLASSIFICATION NO. 4

No changes are proposed for SC 2 – Gas Lighting Service and SC 4 – General Service – Economic Development.

5. SERVICE CLASSIFICATION NO. 7 and SERVICE CLASSIFICATION NO. 8

At this time, the Company does not propose to make any changes to SC 7 – Banking Service and SC 8 – Storage Service. However, as discussed below, it is anticipated that these services could be eliminated with the creation of new balancing services.

C. CUSTOMER BILL IMPACTS

The customer bill impacts resulting from the rate design changes described above for SC 1, SC 3 and SC 5 are contained in Appendix F.

D. FACTOR OF ADJUSTMENT

The Company proposes to update the factor of adjustment used to calculate gas costs to a recent historical average value of 1.0185.

E. RETAILING BACKOUT CREDIT

The proper level of a retailing backout credit to differentiate bundled from unbundled distribution rates depends upon a number of factors that the Company expects will be decided in the upcoming negotiations. For instance, the timing and extent of retail commodity deregulation, the manner in which the Company exercises its obligation to serve, the manner in which the Company manages deliveries of gas into its system, and the nature of transportation service will all influence the level of any credit that may be appropriate. The Company expects to revisit this issue during the course of discussions with interested parties.

F. BALANCING

In Section VI, the Company describes its proposals for phasing in improved balancing services. As this transition occurs, the Company will continue to provide balancing, as it does today in its gas tariff, P.S.C. No. 11 – Schedule for Gas Service, to marketers serving retail customers under SC 3 and SC 5. In the interim, the Company will also continue to provide Banking Service under SC 7 and Storage Service under SC 8. SC 7 and SC 8 will be eliminated as balancing is developed under the CNG DPO and CSC services.

The rates and resulting bill impacts included in this proposal reflect the current balancing services. However, as noted below, the Company proposes to make competitive suppliers, rather than the individual retail customers, responsible for balancing charges. Therefore, balancing charges are included in the resulting bill impacts for SC 3 and SC 5, and are also listed separately.

G. TRANSITION COST RECOVERY

Given the Company's proposal to implement price deregulation and the on-going plans and efforts to mitigate and manage upstream capacity costs, the Company proposes to continue with the current Commission-approved transition cost recovery mechanism for stranded capacity costs resulting from the migration of retail customers to competitive suppliers.[1] That is, net stranded capacity costs are recovered from all firm sales and post-aggregation firm transportation customers. For RG&E, such costs are recovered from customers in SC 1, customers who converted to service under SC 3 after November 1, 1996 and customers in SC 5. The rates and resulting bill impacts included in this proposal reflect the current Commission-approved transition cost recovery mechanism.

As the implementation of full price deregulation proceeds, and as the changes to the Company's upstream capacity portfolio begin to take shape as a result of the long-term strategy that has been undertaken, the Company proposes that the transition cost recovery mechanism be revisited. Upon full deregulation of commodity costs, the Company proposes to switch to a uniform surcharge on all post November 1, 1996 transportation load. This surcharge would be designed to recover all remaining capacity costs over a reasonable period of time. Actual

[1] On November 19, 1998, RG&E filed tariff leaves to implement a transition surcharge mechanism as a result of the Company's October 16, 1998 Interim Settlement Agreement, approved by the Commission on November 9, 1998 in the Order Freezing Base Rates, Limiting Mandatory Assignment of Capacity, and Resolving Other Issues. Although this mechanism was implemented prior to the Commission's February 22, 1999 Order Concerning Recovery of Stranded Capacity Costs, which states the final ruling on transition cost recovery, the mechanism that the Company put in place is in conformance with the Commission's policy on this matter.

transition costs would be tracked against these revenues, and the surcharge would cease once costs are fully recovered.

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SECTION

V

CUSTOMER EDUCATION PLAN

The section presents RG&E's proposals regarding a customer education plan. RG&E has two principal goals with respect to this program. First, the Company intends to comply with the Commission's Policy Statement, working to ensure that customers have "sufficient and accurate information . . . to use in making informed decisions" regarding their choice of gas suppliers (Policy Statement at 4). Achieving this aim will demand recognition of the fact that the Company is only one source of information about choice. The Company will have to coordinate with or influence other communications channels to achieve the best results. Second, the Company intends that all communications efforts ensure that RG&E continues to be a trusted source of information within its community. The Company's primary communications responsibility is to inform customers about the safe and responsible use of its products. Every communications effort in which the Company engages must uphold its reputation for providing accurate, reliable and useful information.

The Company proposes to adopt a multi-part strategy for rolling out this education program. The first element of the strategy is to maintain the Company's position as an unbiased and neutral source of information about choice. Messages must be crafted so as to present all choices available. The second element is to urge customers to use the information provided by RG&E, gather additional information relevant to their specific circumstances and make a choice that is right for their individual situations. The third element is to coordinate the education plan with gas marketers operating in the Company's territory. In the customer's mind, gas marketers may be the most important source of information regarding choice. The information marketers provide must be accurate, complete and consistent with the Company's messages. The fourth element will be to attempt to influence local media to ensure that information distributed through these channels is consistent with messages provided by the Company.

The Company proposes to continue its ongoing program of measuring customer awareness and understanding of retail choice, and to use these measurements to help guide the development of its education program. For many years, the Company has conducted an opinion survey of its residential customers at least annually. RG&E has utilized the nationally-recognized polling firm of RKS Research and Consulting, Inc., to design and administer the survey, and analyze the results. The Company proposes to administer this survey or its equivalent at least annually over the period covered by a settlement in this case, and to use it to collect information regarding customer awareness and understanding of gas choice. Survey respondents will be drawn from residential customers located within the Company's service territory, without regard to whether they purchase commodity services from RG&E or a competitive supplier. The two specific measures are described below.

Customer Awareness of Gas Choice. This measure is defined as the percentage of residential customers in RG&E's gas service territory who are aware that there is choice with regard to gas suppliers. The measure will represent the percentage who answer "yes" to the following question: "Competition among natural gas suppliers in New York State has begun, too. Under this plan, RG&E will continue to deliver your gas, but you'll be able to choose from among different companies that supply gas to your home at varying prices. Are you aware of having choice of gas suppliers?" The surveyor will record a "yes" or "no" answer, or an answer of "not sure" if volunteered by the respondent.

Customer Understanding of Gas Choice. This measure is defined as the percentage of residential gas customers in RG&E's service territory that are aware of gas choice and state that they understand it very clearly or fairly clearly. Specifically, the percentage reported will represent the sum of those who respond "very clearly" or "fairly clearly" to the following question: "How clearly do you understand the way this plan of selecting your gas provider works - very clearly, fairly clearly, not too clearly or not at all clearly?" The surveyor will record the answer as "very clearly," "fairly clearly," "not too clearly," "not at all clearly," or, if volunteered by the respondent, "not sure." The question will immediately follow the question regarding awareness of gas choice, and will only be asked of those customers who respond positively to that question.

Content development will be critical to the design of a successful education program. RG&E envisions a two-step process. The first step will be to gather information from customers. The Company has found through its past experience that content cannot be determined effectively without customer input. In this case, RG&E envisions using focus groups to systematically gather information regarding program elements about which customers want more information, and to determine which communications vehicles would be most effective. The Company also plans to use ongoing contacts through its Community Relations program to gather relevant information. The second step will be to design messages and programs on the basis of the information gathered, test those plans through a focus group technique, and then revise plans accordingly.

Prior to finalizing plans, RG&E proposes to share information regarding those plans with gas marketers operating on its system through a RG&E/Marketer forum. Through this forum, RG&E intends that all suppliers will share information regarding the current environment, ongoing activities and future plans. An open exchange of information will allow for the maximum degree of coordination between information programs, with respect to both timing and content. The goal will be to ensure that customers receive clear, consistent, useful and timely information regarding retail choice programs.

The Company proposes that delivery vehicles for the education program be determined later, on the basis of information gathered from customers as described above. The Company has utilized a wide variety of information channels in the past, and believes that most, if not all, of these same channels will be useful in the future. A matrix summarizing communications channels that RG&E has successfully utilized in the past is included at the end of this Section as Figure V-A.

The Company proposes to devote incremental expenditures to the execution of its education plan. Certain communications expenditures are part of RG&E's ongoing business and have been planned for in the development of the revenue requirements presentation described previously. These efforts include web page development and maintenance, the Solutions Page, bill inserts, newsletters, community and media relations activities, customer surveys and gas marketer meetings. However, the education program described in this Section would call for additional expenditures. Final budgetary plans will depend, of course, on program plans developed with customer input, so no definite amounts can be presented at this time. The Company proposes instead to build into revenue requirements an amount expected to be adequate to fund an appropriate program, and to true up to actual expenditures after the term of a settlement reached through this proceeding. For planning purposes, the Company estimates that an amount of $372,000 per year should be sufficient, calculated as follows.

- Eight local focus groups - $20,000
- Production of two 30-second TV spots - $120,000
- Production of one 60-second radio spots - $8,000
- Media buys - one 13-week flight - $75,000
- Production of one informational video - $125,000
- Fact kit preparation and mailing - $15,000
- Business customer meetings - six - $9,000

As a final element of its proposal, the Company proposes to submit to Staff an annual customer education report. This report would include measurement results, a description of RG&E activities and expenditures, a summary of gas marketer activities and expenditures (to be provided primarily by the marketers), and a summary of media reports regarding retail access in the local community.

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FIGURE V-A

Communications Vehicles Matrix

	Vehicle	Audience
1	**Company Web Page** **www.rge.com** (Internet Information Site) *4-6 weeks prep. Time*	Retail & distribution customers, employees and others *via* web site access.
2	**Solutions Page** (monthly O&E advertising) *2-4 weeks prep. Time* **"Soluciones"** (Spanish version) *4-6 weeks prep. Time*	Readers of Democrat & Chronicle *Weekend* section of Thursday's paper. Monthly frequency with 180,000 circulation.
3	**Highlights** (monthly bill insert) *6-8 weeks prep. Time*	Residential customers (@342,000) in RG&E's service territory.
4	**Point of View** (newsletter) *6-8 weeks prep. Time*	Key opinion leaders(government, business & human service agencies, & employees)
5	**RG&E News** (monthly employee newsletter) *6-8 weeks prep. Time*	Employees & retirees
6	**News Announcements** *2-4 weeks prep. Time*	Statewide and local
7	**Community Relations** *Ongoing*	Local community groups and agencies
8	**Media Relations** *Ongoing*	Print & broadcast media contacts
9	**Presentations** *8-10 weeks prep. Time*	Graphics presentations will be developed for key constituency, customer contact, employee & others requesting information.
10	**Senior Connection** (newsletter) *4-6 weeks prep. Time*	Elderly customers in RG&E service territory & the agencies serving them. Circ: 15,000
11	**ERIN Messages** (internal e-mail system) *1 week or less*	Employees.
12	**ON-HOLD Messages** *4-6 weeks prep. Time*	Customer inquiries.
13	**Paid Advertising** *6-8 weeks prep. Time*	Entire customer base.
14	**Neighborhood newspapers, newsletters, & other publications** *4-6 weeks prep. Time*	Entire customer base.
15	**Business Customer Meetings** *4-6 weeks prep. Time*	Meetings w/large (SC No. 3) C&I customers
16	**Informational Videos** *___ weeks prep. Time*	Entire customer base, employees
17	**E-Choice Fact Kit** *Exists, update*	All. Based on www access or phone call to RG&E for mailing.

SECTION

VI

FACILITATING THE MOVE TO COMPETITION

In this Section, the Company describes additional proposals meant to allow for the deregulation of retail gas commodity prices. This discussion is divided into five subsections. The first deals with the nature of distribution service, the second with the management of gas deliveries into the system, the third with communications between gas marketers and the utility, the fourth with the Company's proposed plan to deregulate prices, and the fifth with the utility's obligation to serve.

A. THE NATURE OF DISTRIBUTION SERVICE

In RG&E's service territory, electric distribution service is provided through the innovative single-retailer model, approved by the Commission in Case 96-E-0898, RG&E's electric Competitive Opportunities proceeding. In this model, the competitive supplier becomes the customer of the distribution company and that entity bundles distribution service, commodity services and potentially others for resale to retail customers. In this way, the retail customer continues to deal with one supplier for energy services, and receives a single bill for that service from the chosen supplier. The retail customer continues to call RG&E for emergencies and outages, and may choose to deal with RG&E directly for other service issues.

In contrast, the Company provides gas distribution service under the older two-retailer model. In this model, RG&E provides distribution service directly to the retail customer, and bills the customer directly for that service. The competitive supplier sells commodity services only, and bills the retail customer separately for that service. In RG&E's program as it is currently structured, there are differences among customer groups in the character of distribution service. Large volume customers, those consuming at least 5,000 DT per year, are individually responsible for providing a sufficient quantity of gas to meet their needs. In all cases, however, the customer's supplier acts as the customer's agent for this purpose, and in general suppliers group most of their customers together in a single balance control pool for the purposes of managing deliveries. Small volume customers, also known as "aggregation" customers, are responsible for choosing a qualified supplier, but that supplier is responsible for providing adequate gas supplies. In both cases, although the gas marketer controls the supply of gas provided for the customer, the tariff calls for balancing charges to be collected from retail customers. These charges are intended to cover the cost to RG&E of making up differences between gas consumed by the customer and the gas delivered on behalf of that customer on a daily and hourly basis.

The Company believes that the single-retailer model is far superior to the two-retailer model. For one thing, it is by far the simplest and clearest approach for retail customers. In essence, the single retailer model allows the competitive supplier to take on the entire merchant and "service bundler" role of the utility. In RG&E's territory, of course, adoption of the single-retailer approach for gas service would allow retail customers to benefit from the model for both electric and gas service, further simplifying retail choice. Simplicity, of course, provides multiple benefits. It should lead to greater customer acceptance of the program and, therefore, greater participation in retail access; it should lower barriers to entry for competitive suppliers; and it should facilitate communications and education programs regarding retail access, leading to greater effectiveness.

The single retailer model also provides for the least possible duplication of services between the utility and competitive suppliers. For example, it allows for a single bill to be provided for the retail customer. This model should, therefore, lead to least cost energy services for the retail customer. Finally, and perhaps most importantly, the model allows for a sensible and practical relationship between the utility and competitive suppliers, that of a supplier and a customer. This should allow for the highest possible degree of mutual cooperation and support in providing energy services to retail customers.

In the short run, however, the Commission is considering its policy toward billing issues and the single-retailer model. In Case 99-M-0631, the Commission issued a request for comments regarding the entire range of billing issues and asked parties to comment specifically on the single-retailer model. A policy statement or order from the Commission is expected in the near future. This issuance could, in theory, support further implementation of the single-retailer model, oppose such steps, or support other options altogether. Until the Commission's policy with respect to these issues is clear, it would be premature to propose implementation of the single-retailer approach in this case. Rather, the Company proposes to act on the Commission's recommendations when they are known. If the Commission acts prior to the conclusion of negotiations in this case, the Company is prepared considered any relevant issues in this proceeding.

However, in the short run, the Company does propose to implement a number of improvements to its two-retail program. The first is to create an explicit, tariffed relationship between the Company and suppliers to large volume transportation gas customers. Currently, relationships with these suppliers are based entirely on operating procedures developed by the Company. Specifically, the Company proposes that suppliers to large volume customers would be required to qualify under the "supplier service" provisions of its tariff, known as Service

Classification ("SC") No. 6 ("SC 6"). The Company proposes a number of changes to SC 6 intended to implement a mutually beneficial and clearly understood contractual relationship.

The Company also proposes a second set of changes, intended to make competitive suppliers, rather than individual retail customers, responsible for balancing charges. This change would place responsibility for these charges on the entity that is able to influence them. Also, balancing services are expected to be offered in the future by suppliers other than the Company.[1] Making suppliers responsible for balancing charges will allow them to determine the appropriate trade-offs between suppliers of those services. Corresponding changes are proposed for the retail transportation service classifications, SC Nos. 3 and 5.

In addition, the Company proposes a third set of changes that would move certain detailed operating procedures out of the tariff and into RG&E's gas supplier operating manual.[2] Finally, RG&E proposes a number of minor "housekeeping" changes, intended to improve the organization and clarity of the tariff.

Appendix H to this report provides a summary of all proposed changes, including specific references to the tariff.

B. MANAGING GAS DELIVERIES

As noted above, in order to allow for deregulation of commodity prices, competitive commodity suppliers must ultimately take on the responsibility of matching daily and hourly flows into the system with the daily and hourly consumption of the customers they serve, and for providing supplies with a level of reliability equal to that currently provided by the utilities. The

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1 The Company's proposals to allow gas marketers to take advantage of these services is described in the following subsection.

2 In Case 97-G-1380, the Commission recently ordered all gas utilities to create and distribute such manuals by late March. RG&E has already made portions of its manual available to marketers through its web site, www.rge.com, and will continue development of this document in accordance with the Commission's order.

process has, of course, been ongoing since the initiation of transportation service in the mid-1980s. As recently as November 1999, improvements were implemented in New York and specifically in RG&E's territory. However, the regulated merchant function of the LDC still bears the burden of ensuring that adequate gas supplies are delivered into the system at all times; competitive suppliers bear a much lighter burden.

The Company proposes to address this barrier to competition by phasing in new responsibilities for competitive suppliers over the next two years. The first phase ideally would begin on May 1, 2000. At this time, suppliers serving daily metered loads would acquire the responsibility to follow those loads on a daily basis. "On-system" balancing, as it is known in the tariff, has been an option since November 1996, but no suppliers have utilized it. The Company makes this proposal under the assumptions that CNGT's proposed DPO/CSC service will be available prior to that time, and that this service will allow suppliers to economically manage deliveries.[3] To the extent that CNGT's new service is not available at that time, implementation of this phase later in the year is possible, although complicated by the fact that in-field transfers of stored gas would most likely be necessary. Also in this phase, RG&E

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3 On October 8, 1999, CNG Transmission Corporation ("CNG"), filed as part of its FERC Gas Tariff, Second Revised Volume No. 1, tariff sheets proposing two new rate schedules, Rate Schedules DPO and CSC, together with related changes. The purpose of CNG's filing is to implement two new services designed to allow CNG and its shippers to better serve an unbundled retail market. The Delivery Point Operator or DPO service is designed to give LDCs such as RG&E, and potentially others that operate physical points of interconnection between CNG and the LDC system (the "citygate") the ability to meet any swings in demand or supply at the citygate without the necessity that the DPO hold contract service rights sufficient to absorb the level of potential swings. The Citygate Swing Customer ("CSC") Service is a companion service to the Rate Schedule DPO service. This schedule is designed primarily to allow shippers behind the DPO's citygate to receive no-notice service directly from CNG. On October 20, 1999, RG&E filed a Motion to Intervene and Protest in Docket No. RP00-21-000, CNG's DPO/CSC Filing, and on January 14, 2000, RG&E filed comments to CNG's December 23, 1999 Modification to the DPO/CSC Proposal. In both cases, RG&E stated that it does not object to the concepts of the DPO and CSC, but rather opposes certain features of CNG's proposal that would place undue burden on the Company and other LDCs who participate in the program. The Company is confident that a reasonable resolution of these issues will be forthcoming.

proposes to allow intra-month nomination changes for suppliers to small-volume customers, in order to allow for a closer match between deliveries and consumption for this group.

The second phase would begin on April 1, 2001, when RG&E's current contract for no-notice storage with CNGT expires. At that point, RG&E proposes that suppliers serving monthly-metered loads take on the responsibility of matching deliveries to consumption on a daily basis. Since actual measurements for these loads would not be available, the Company would forecast loads each day using a mutually agreeable process. Also at this time, the Company proposes to require that all suppliers maintain transportation contracts that allow their hourly deliveries to match the expected hourly profile of their customer group. In addition to moving toward a system of equal responsibilities for all suppliers, both changes would allow the Company to minimize the amount of no-notice storage it contracts for after the expiration of the current contract. This is consistent with the Commission's directive to minimize future contractual obligations.

The final phase would begin on May 1, 2002. At that time, the Company proposes to equalize responsibilities for all suppliers serving load on the system, regardless of their affiliation with the LDC. This would allow for retail commodity price deregulation, as envisioned by the Commission. RG&E's proposal would also ensure that delivery system reliability is equal to that in place today, as the Commission requires. The specific changes would be to require all suppliers to make intra-day nomination changes when required by the distribution company, to meet delivery point constraints at all times, and to contract for primary, firm transportation capacity, from the citygate to a liquid trading point, adequate to meet the needs of their firm customers at all times during the year.[4] Interruptible loads would not be bound by this last requirement.

The Company proposes to make the necessary tariff filings to implement these changes four to six months in advance of each change. The timing of phase 1, of course, will not allow for that degree of lead time. Of course, the Company would request that the Commission expedite the handling of each filing in order to allow for efficient implementation of the changes without concern for regulatory uncertainty.

Appendix I presents these proposals in matrix form. It includes as well a summary of changes implemented in November 1996 and November 1999, in order to provide some historical perspective.

C. COMMUNICATIONS BETWEEN GAS MARKETERS AND THE UTILITY

As the Commission has recognized in Case 97-G-1380, communications between marketers and LDCs is critical to the continued reliable provision of service to retail customers. As described in Section I, a number of parties worked together under the auspices of that case to develop guidelines for "communications protocols" to formalize communications practices between marketers and LDCs. During the previous round of negotiations in the instant case, the Company worked with several marketers to develop a communications protocol suitable for use in this territory. The Company has taken the result of that collaboration and modified it somewhat for consistency with the proposals being made at this time. It presents that document in Appendix K for the consideration of the parties in the upcoming round of negotiations.

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4 While CNG south Point and Dawn appear likely at this time to be sufficiently liquid to support reliability, the Company proposes to undertake additional analysis to verify this. Of course, the liquidity of any trading point may change overtime. Further, the Commission's ongoing consideration of reliability issues may influence this determination.

D. PROPOSAL TO DEREGULATE RETAIL COMMODITY PRICES

Consistent with other elements of the Company's proposal, RG&E proposes that the Commission deregulate retail commodity prices on May 1, 2002, upon implementation of equal reliability responsibilities for all gas suppliers. The Company believes that an earlier date could also be feasible, if reliability responsibilities can be equalized sooner.

Specifically, the Company proposes that retail commodity prices be deregulated as of the indicated date. At that time, the retailing arm of the Company would be free to charge competitive prices for commodity services to its customers, and it would be required to provide a separate bill for those services. Distribution prices, of course, would continue to be regulated as they are today. All retail customers would be billed for those services under SC 3 or SC 5, as appropriate. The Company's retailing operations would be moved to an affiliated company at that time, and existing standards of conduct governing affiliate relationships would apply to the interactions between the Company and that affiliate.[5]

Upstream assets would continue to be the responsibility of the regulated company. Any costs for which the Company remains obligated after all mitigation efforts have been carried out will be recovered from all post-November 1996 transportation throughput through a uniform surcharge. Revenues collected under this surcharge will be tracked against costs, and differences will be trued-up periodically. The Company will undertake the aggressive cost mitigation efforts described in Section II of this document. RG&E's retail affiliate will be treated like any other entity for purposes of capacity releases or other sales of capacity.

RG&E proposes that, concomitant with commodity price deregulation, the Commission implement a market power monitoring plan. Under this proposal, Staff would gather information

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[5] These standards are contained in Schedule I of the Company's Competitive Opportunities Settlement.

necessary to determine whether any supplier might be exercising market power. Specifically, all suppliers would be required to report to the Department of Public Service, through trade secret filings, annual sales and revenues for the following market segments: residential, small non-residential (less than 5000 DT per year) and large non-residential. Any interested party, including Staff, would be allowed to petition the Commission for an investigation of a particular supplier, upon providing evidence that the supplier was able to hold prices above market levels. The Commission would select an appropriate procedural approach for resolving the petition, given the specific situation. If the PSC determined that the supplier was in fact holding prices above market level, it would impose whatever remedy was appropriate and available to it under the law.

E. OBLIGATION TO SERVE

In order to fulfill its obligations under the law, the Company proposes that it arrange for one or more "backstop" providers of service through competitive market solicitations. These providers would serve all customers that found themselves unable or unwilling to acquire a supplier through the market, or who were left without a supplier due to default. For residential customers, the Company would solicit bids from qualified competitive suppliers that are willing to provide service under the terms and conditions required by HEFPA. The bidders would commit to selling service to customers under fixed or indexed prices, which would be explicitly stated in the proposal. The supplier would also be free to propose an additional subsidy amount, to be provided by the distribution company, to defray the additional costs inherent in providing services under the requisite terms. The distribution company would recover these costs through a surcharge on all throughput. For non-residential service, bidders would be free to propose to segment customers on any reasonable basis, but within those segments pricing would be uniform. Again, prices would have to be explicitly stated in proposals. Bidders would also be free to propose other reasonable terms and conditions of service. In the case of the non-residential class, competitive bidders would be compensated only through their own billings.

Finally, although not required by the law, the Company proposes to continue its Low Income Assistance Partnership ("LIAP") program for a two-year period, and to implement certain program improvements. Each year, the program would be made available to 350 low-income customers of the Company who are in arrears. They must have participated in, or agree to participate in, a weatherization program with another agency. Over their two-year participation in the program, these customers would receive household budget counseling. Collection activity would cease during their participation in the program, and all arrears would be forgiven by the conclusion of the customer's participation in the program. Program costs are projected to be $1.8 million per year. The Company proposes to collect these costs through a surcharge on all throughput. Appendix L describes the proposed program in detail.

APPENDIX A

IMPROVEMENTS TO TRANSPORTATION GAS PROGRAM

IMPROVEMENTS
TO
TRANSPORTATION GAS PROGRAM

During 1998 and 1999, RG&E made numerous improvements in its transportation gas program. These are listed below.

- ***Service Classification No. 5 consumption information***. Late in 1998, the Company initiated a system whereby meter reads and imbalance information are posted to the Company's secure web site on a billing cycle basis. This allows marketers ready access to the information they need to bill their customers and track imbalances.

- ***Consolidation of the transportation gas program.*** In 1999, the Company brought together in one department all aspects of the transportation gas program, including enrollment processing, billing, balancing and settlement, supplier account management and program planning. This has allowed for a high degree of collaboration between employees who operate the program and has set the stage for the other improvements described below.

- ***Gas Marketer Operating Group***. In mid-1999, the Company initiated a regular series of gas marketer operating group meetings, held in May, July and October. These meetings are planned to take place on a quarterly basis for the foreseeable future, and will cover topics of concern to the Company or marketers regarding the transportation gas program. Topics covered at the 1999 meeting include distribution system constraints, delivery point operating procedures, communications, group by-laws, Y2K preparations, winter peak day requirements, gas emergency drill planning, therms running balance cash-out, discontinuance of service forms and procedure, capacity release, standby service, and procedures regarding firm primary delivery point capacity.

- ***Therms running balance cash-out***. In the Company's small-volume transportation program, imbalances are tracked on a customer-by-customer basis. The cumulative imbalance for a customer is known as the "therms running balance." Prior to October 1999, when a customer switched suppliers or returned to regulated service, the therms running balance was cashed out, and the customer received a credit or a charge representing the value of the imbalance at the time of the switch. This led to customer confusion, as most marketers bill customers on the basis of meter reads, and so the customers generally felt they had already paid for the appropriate amount of gas through their usual monthly billings from the supplier. Similarly, the marketers generally felt that they should be responsible for the credit or surcharge, as that amount represented the difference between what they had delivered on behalf of the customer and the customer's actual consumption. Working together, the Company and marketers devised a plan to cash out the marketer, rather than the customer, for the therms running balance. The Company and marketers also worked together on a communications plan and letter to inform customers of the change.

- ***Wholesale account managers***. In October 1999, the Company assigned an Account Manager to each gas marketer and informed the marketers of this new contact. At RG&E, a Wholesale Account Manager is the primary point of contact for all inquiries from the marketer. The Account Manager provides for a high level of continuity in the relationship between the Company and the marketer, and allows for quicker response to inquiries and requests.

- ***Gas Emergency Drill***. In October 1999, marketers and the Company participated in a joint emergency exercise. The drill tested procedures required to implement a load curtailment, and included testing procedures for initiating contact with marketers on a emergency basis.

- ***Delivery point planning process***. As described elsewhere in this filing, in order to reliably operate its distribution system, the Company must ensure that deliveries to each of its two city gates satisfy certain physical constraints. In November 1999, the Company initiated a planning process designed to ensure reliable operation of the system over the spectrum of operating conditions even as transportation gas load continues to grow. Although this change is controversial among some marketers, it is required to preserve reliability as the transition to system supply through competitive suppliers progresses, and thus should be considered a program improvement. The Company hopes that, by working with marketers over the coming months and years, the negative aspects of this change can be ameliorated.

- ***Supplier manual and forms***. In December 1999, prior to the Commission's Order requiring the development of supplier manuals, the Company posted the initial sections of its supplier operating manual on its public web site, at www.rge.com/gasmanual.html. This first version of the manual contains sections regarding the supplier qualification process, an enrollment calendar, delivery point operating constraints, a glossary of terms, and forms required for various aspects of the program.

- ***Automated enrollment processing***. In February 2000, the Company will initiate an optional procedure allowing for electronic processing of customer enrollments. This process will allow marketers to provide enrollment requests via an electronic file. The data will be validated automatically, and consumption history information for each transfer will be posted automatically to the Company's secure web site, where it will be available to the marketer making the enrollment request.

- ***Continuous enrollments***. Also in February 2000, the Company will initiate a process of continuous enrollments for small-volume transportation customers. Up until now, all transfers between suppliers or from RG&E to a competitive supplier have been made at the beginning of a calendar month, resulting in two prorated bills for the customer. From February on, the Company will switch small-volume customers on their scheduled billing date, resulting in a simpler and probably quicker process for the customer. This change will also be consistent with the electric retail access program, so a customer switching both electric and gas service will be switched for both services on the same date.

APPENDIX B

GAS RESTRUCTURING PROPOSAL - SUMMARY

Rochester Gas and Electric Corp
Gas Restructuring Proposal – Summary

1. Strategy to hold new capacity contracts to a minimum; Quantification of potential stranded costs and plan to mitigate and manage them

Item	Proposal
LONG-TERM STRATEGY	Purchase all gas required for retail customers at the city gate and eliminate long-term capacity commitments
TRANSITION STRATEGY	Implement a three-prong approach to identify opportunities to minimize capacity holdings and mitigate capacity costs: ▪ Conduct negotiations with upstream pipelines to reduce costs and/or commitments in a manner that is acceptable to all parties ▪ Conduct an "Open Season" bidding process whereby the Company offers interested parties the opportunity to bid on the Company's current capacity holdings ▪ Conduct a Request for Proposal (RFP) process whereby interested bidders would take assignment of a share of the Company's remaining capacity holdings, in return for supplying gas at the city gate to serve remaining retail load

2. A long-term rate plan with a goal or reducing or freezing rates

Item	Proposal
REVENUE REQUIREMENTS ANALYSIS	Supports a revenue increase of $14.2 million (5.4%) for the rate year ending June 30, 2001, and a revenue increase of $4.0 million (1.6%) for the rate year ending June 30, 2002.
REVENUE PROPOSAL	The Company proposes to resolve revenue requirements through the course of negotiations, recognizing that revenue requirements are inextricably connected to every other aspect of this proposal.
OTHER	▪ Provision included to defer costs for future recovery for any mandates, catastrophic events and competition implementation costs ▪ Provision included to adjust filed revenue requirements should agreements be reached that would implement new programs or enhance existing programs

R371246.1

3. A plan to further unbundle rates

Item	Proposal
FACTOR OF ADJUSTMENT	The factor of adjustment will be set at 1.85% for the two-year period. The factor will cover losses in base rates and upstream costs.
CUSTOMER CHARGES	The monthly customer charge, net of the base cost of gas, will be increased to $10 per month, for Service Classifications 1 and 5. The charge will increase by $2.10 in the first rate year and by $2.09 in the second year. A corresponding change will be made to the Service Classification No. 3 minimum charge
IMPLEMENTATION OF NEW GCA REGULATIONS	▪ Gas costs will be rolled out of base rates ▪ Certain other changes will be implemented consistent with the Commission's Order on the GCA
SC1, SC 5 BLOCK STRUCTURE	The last two rate blocks will be removed. Revenue neutrality will be maintained.
TRANSITION COST RECOVERY	Continue with current Commission-approved transition cost recovery mechanism. The transition cost recovery mechanism will be revisited when retail prices are fully deregulated. At such time, Company proposes to switch to a uniform surcharge on all post-11/1/96 transportation load.
BALANCING CHARGES	▪ Calculate later on basis of agreements reached in negotiations and resolution of CNG's DPO/CSC service.
REDESIGN OF DELIVERY RATES	The Company is currently completing an embedded cost of service study. The redesign of delivery rates will be determined upon the completion of an updated cost study. This Company will supplement this proposal with the updated cost study.

4. A plan to enhance customer education programs and facilitate customer participation

Item Proposal

CUSTOMER EDUCATION PLAN

- Continue measuring customer awareness and customer understanding in Company-sponsored surveys. The results of these measurements will be used to continuously assess the effectiveness of the Company's customer education efforts
- Utilize focus groups and RG&E/Marketer forums to guide development of customer education content
- Utilize existing methods for delivery of customer education
- Provide an annual report to Staff, working with the Marketers, on customer education efforts. Such a report will include, measurement results, RG&E activities and expenditures, marketer activities and expenditures and media reports (i.e., summary of information reported through major media channels within the local community)

5. Phase-in full deregulation of retail prices

Item Proposal

RETAIL ACCESS

Improve two-retailer program in the following respects:

- Modify Service Classification No. 6 – Supplier Service to include suppliers serving customers under Service Classification No. 3
- Apply balancing charges to suppliers and not retail customers
- Adopt a communications protocol governing communications between the marketers and the Company, as encouraged by the Commission in the "Reliability Communication Working Group Report" from Case 97-G-1380
- Develop a Gas Supplier Operating Manual, as ordered by the Commission in the December 21, 1999 Order Concerning Reliability in Case 97-G-1380

MANAGING GAS DELIVERIES

Phase in plans over the next two years for suppliers to take responsibility of matching daily and hourly flows into the system with the daily and hourly consumption of the customers they serve. Appendix H contains all proposed changes and specific references to the tariff. Tariff changes will be filed four to six months in advance of each change.

Phase I: Begins on May 1, 2000. Suppliers serving daily metered load would acquire the responsibility of matching deliveries to consumption on a daily basis, subject to the availability of CNG's DPO/CSC service. The Company also proposes to allow intra-month nominations for suppliers to small volume customers.

Phase II: Begins on April 1, 2001. Suppliers serving monthly metered loads acquire the responsibility of matching deliveries to consumption on a daily basis. The Company also proposes to require all suppliers to maintain transportation contracts that allow their hourly deliveries to match the expected hourly profile of their customer group.

Phase III: Begins on May 1, 2002. Final phase to require all suppliers to make intraday nominations when required by the LDC, meet delivery point constraints at all times and contract for primary, firm transportation capacity to meet the needs of firm customers at all times.

DEREGULATION OF RETAIL COMMODITY PRICES

Fully deregulate retail commodity prices. The target date for implementation is May 2002, in conjunction with final phase-in of managing gas deliveries. Details include:

- Structural separation of RG&E retailing function from distribution function and application of standards of conduct from electric settlement agreement pertaining to affiliate relationships
- Costs for remaining upstream assets will remain with the distribution company and be recovered from all post November 1996 transportation load through a uniform surcharge
- Propose that Commission implement a market monitoring plan

CONTINUING SERVICE OBLIGATIONS

- Residential customers: For customers unable or unwilling to acquire a supplier through the market, the Company will provide service through competitive selection of a qualified supplier willing to provide service under the terms and conditions required by HEFPA. The additional costs for providing this service would be recovered by the distribution company through a surcharge on all throughput
- Non-residential customers: For customers unable or unwilling to acquire a supplier through the market, the Company will provide service through competitive selection of a qualified supplier.

6. Other Proposals

Item **Proposal**

LOW INCOME PROGRAM

Continue the current Low Income Assistance Partnership program for a two-year period and implement program improvements. These improvements include requiring customer participation in a weatherization program with an outside agency. Also, over their two year participation in the program, customers will receive household budget counseling. Details are presented in Appendix L.

Program costs are projected to be $1.8 million per year. The Company proposes to collect program costs through a surcharge on all throughput.

APPENDIX C

UPDATED REPORT ON NATURAL GAS CAPACITY COST MITIGATION

PUBLIC SERVICE COMMISSION
OF THE STATE OF NEW YORK

CASE 98-G-1589

IN THE MATTER OF
ROCHESTER GAS AND ELECTRIC CORPORATION'S
PLANS FOR GAS RATES AND RESTRUCTURING

ROCHESTER GAS AND ELECTRIC CORPORATION

UPDATED REPORT ON NATURAL GAS CAPACITY COST MITIGATION

JANUARY 28, 2000

TABLE OF CONTENTS

Page

I. INTRODUCTION 1

II. HISTORICAL BACKGROUND 3

III. RG&E'S CURRENT PORTFOLIO 6

- A. PIPELINE CAPACITY 6
- B. KEY ISSUES PERTAINING TO CONTRACTS 7
- C. OPERATIONAL CONSTRAINTS 9
- D. SUPPLY PORTFOLIO 10
- E. ASSET MANAGEMENT ARRANGEMENTS 11
- F. OTHER COST MITIGATION MEASURES 11

IV. VALUE OF CURRENT PORTFOLIO 13

- A. METHODOLOGY 13
- B. SENSITIVITIES 13

V. PROJECTION OF THE FUTURE 14

- A. LOAD FORECAST 14
- B. MIGRATION TO MARKETERS 15
- C. BALANCING REQUIREMENTS 15

VI. RG&E'S LONG-TERM STRATEGY 15

VII. RG&E'S TRANSITION STRATEGY AND IMPLEMENTATION 17

- A. GOALS DURING TRANSITION 17
- B. THREE-PRONGED STRATEGY 17
  - *1. Negotiation with Pipelines* *18*
  - *2. Open Season to Assign Capacity* *19*
  - *3. Market Service RFP* *20*
- C. SUMMARY 22

VIII. ACTION BY STAFF AND THE COMMISSION 22

IX. CONCLUSION 23

APPENDIX A - City Gate Deliverability vs Production-Area and Storage Deliverability
APPENDIX B - Upstream Capacity Study (Excerpts)
APPENDIX D - Transportation and Storage Contracts
APPENDIX F - Empire City Gate – Minimum and Maximum Percentage of Total System
APPENDIX G - Current Supply Portfolio
APPENDIX J - Summary of FERC Rulemaking Proceedings and Inquiries
APPENDIX K - Participation in FERC Proceedings
APPENDIX L - Migration Forecast
APPENDIX N - Open Season Solicitation Package
APPENDIX O - Request for Proposals
APPENDIX P - Questions and Answers Regarding Request for Proposals
APPENDIX Q - Presentation Materials

PUBLIC SERVICE COMMISSION
OF THE STATE OF NEW YORK

CASE 98-G-1589

IN THE MATTER OF
ROCHESTER GAS AND ELECTRIC CORPORATION'S
PLANS FOR GAS RATES AND RESTRUCTURING

ROCHESTER GAS AND ELECTRIC CORPORATION

UPDATED REPORT ON
NATURAL GAS CAPACITY COST MITIGATION

I. INTRODUCTION

On November 29, 1999, Rochester Gas and Electric Corporation ("RG&E," the "Company") submitted its Report to the Staff of the Department of Public Service on Natural Gas Capacity Cost Mitigation") ("November 29 Report") pursuant to the Company's September 14, 1999 "Proposal for Capacity Release Revenue Imputation and Capacity Cost Mitigation Issues and Framework for Resuming Settlement Negotiations" (the "Proposal") that was approved by the Commission in its Order Approving Petition issued September 30, 1999 in this proceeding (the "Order"). On December 10, 1999 and December 16, 1999, RG&E provided Supplements[1] to the staff of the Department of Public Service ("Staff"), addressing further developments that had occurred with regard to the Company's discussions with upstream pipelines. The November 29 Report described the actions RG&E had taken and planned to take, as well as the progress the Company had made, to reduce upstream gas capacity costs.

Consistent with the Proposal, the November 29 Report was also intended to provide sufficient detail about the Company's actions, plans and progress to enable Staff to respond, as

[1] Designated Supplement No. 1 and Supplement No. 2, respectively.

called for in the Proposal, with its view of RG&E's efforts and plans. Staff provided its response by letter dated January 3, 2000.

The instant document is an updated version of the November 29 Report[2] and is included as an integral part of the public filing which the Proposal requires the Company to make by January 28, 2000 (the "January 28 Filing") to address the rate and restructuring issues presented in the Commission's Policy Statement Concerning the Future of the Natural Gas Industry in New York State ("Policy Statement") issued November 3, 1998 in Cases 93-G-0932[3] and 97-G-1380[4] and the Commission's Order Clarifying Gas Policy Statement issued April 1, 1999 in Case 97-G-1380.

As contemplated in the Proposal, RG&E has consulted with Staff regularly, via conference call and in person, both before and after submission of the November 29 Report, to inform Staff of the Company's plans and progress. The ideas and feedback RG&E received from Staff has been helpful in shaping the strategies discussed in the November 29 Report and in this Updated Report. RG&E appreciates Staff's commitment of time and thought to this process.

As the Table of Contents indicates, in addressing the Company's actions and plans, this Report is organized to include the following elements: historical background; current portfolio of transportation, storage and supply assets and the management of these assets; current value of the Company's portfolio; RG&E's view of the future with respect to load growth and migration; the Company's long-term strategy to address the future; the Company's transition implementation strategy to bridge from the present to the long-term strategy; and recommendations for regulatory action to support both the transition and long-term strategies.

The final element noted above is particularly important in this context. Even the most thoroughly developed, practicable strategy will founder if it lacks the necessary support from Staff and the Commission. RG&E envisions such support as taking the form of an on-going, iterative process that should continue in the negotiations to be held in this proceeding. Along

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2 To avoid confusion, where Appendices to the November 29 Report are not referenced and/or in this document, the letter designations of the remaining Appendices have not been changed.

3 Proceeding on Motion of the Commission to Address Issues Associated with the Restructuring of the Emerging Competitive Natural Gas Industry.

4 In the Matter of Issues Associated with the Future of the Natural Gas Industry and the Role of Local Gas Distribution Companies.

with further Commission policy direction, such initial input will, over the longer term, help to shape and implement a practicable transition to the end state presented here.

II. HISTORICAL BACKGROUND

RG&E currently serves a total of approximately 285,000 customers, broken down as follows: 274,000 retail (SC 1) customers; 739 transportation (SC 3) customers; and 10,400 aggregated end use (SC 5) customers. To serve primarily the retail requirements of the foregoing SC 1 customers, as well as the "swing" requirements of non-SC 1 customers, RG&E has contracts for transportation and storage capacity totaling approximately 450,000 DT/day.[5] Of that amount, 172,500 DT/day is provided through the Company's Mendon city gate served by Empire State Pipeline ("Empire") and 277,690 DT/day is provided through the Caledonia city gate served by CNG Transmission Corporation ("CNG").[6] Upstream of Empire, RG&E has transportation contracts with TransCanada PipeLines Limited ("TransCanada"), Union Gas Limited ("Union"),[7] Great Lakes Gas Transmission Limited Partnership ("Great Lakes"), and ANR Pipeline Company ("ANR") (transportation and storage). Similarly, upstream of CNG, which provides transportation and no-notice storage, RG&E has transportation contracts with Tennessee Gas Pipeline Company ("Tennessee"), Texas Gas Transmission Corporation ("Texas Gas"), Texas Eastern Transmission Corporation ("Texas Eastern"), and Transcontinental Pipeline Company ("Transco").

On January 19, 1994, RG&E experienced its maximum daily throughput of approximately 474,000 DT, of which 391,000 DT was for retail customers and 83,000 DT was for transportation customers. During the early 1990s, the Company's design day was based on extrapolation of the 474,000 DT load to more severe weather conditions that occurred on

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5 Although city gate deliverability is currently at 450,000 DT per day, capacity originating from the production area is substantially less than that figure. In the near term, permanent and long-term capacity release transactions and contract terminations have created a portfolio that allows for market area supply purchases and provides for an adequate capacity reserve to meet reliability requirements. Over time, however, as CNG contracts expire, RG&E would expect to purchase more gas in the market area, as liquidity of transportation in that area increases. Appendix A to this Report shows a comparison of design day city gate deliverability with production area and storage deliverability from the present through 2008.

6 The quantity indicated for CNG includes capacity to serve the Pavilion District which has receipt points on CNG upstream of Caledonia.

7 The Union service agreement is assigned to TransCanada to enable TransCanada to provide point-to-point service from Dawn to Chippawa.

January 17, 1982 (an average temperature of minus 7 degrees Fahrenheit and average wind speed of 24 MPH). The design day would be approximately 520,000 DT, with an occurrence rate of once in over 100 years. Under that scenario, it was estimated that the throughput for retail load would account for approximately 420,000 DT, transportation throughput would be approximately 100,000 DT, and swing capacity for transportation would be approximately 30,000 DT.

Since the foregoing design day was developed, customers have continued to migrate to marketers and, as a result, the level of capacity RG&E must maintain to meet the design day has declined. In addition, RG&E has reviewed the weather history and plotted the probability of occurrence of minimum temperatures. The Company's current design day of 470,000 DT throughput is based on one occurrence in 30 years for a minus 7 degree day with the same wind conditions that occurred in 1994. The gross transportation component of this figure is 120,000 DT which includes back-up requirements of 20,000 DT).[8] The remaining 350,000 DT retail requirement is expected to decline as retail customers continue to migrate to gas marketers.

The critical challenge RG&E faces with respect to the upstream gas business is managing the cost and amount of capacity needed to serve remaining retail load as that load migrates to retail access. Staff has indicated that, currently, RG&E's upstream capacity costs are noticeably higher than the New York State average. Further, this cost difference is projected to increase significantly over the next several years if the effects of increased reliance on the relatively more expensive Empire system, coupled with reduced system throughput resulting from migration, are not managed.

In the past, much of the concern regarding RG&E's gas costs has focused on the surplus capacity the Company had as a result of the circumstances surrounding the Company's efforts, at the Commission's direction, to reduce its exclusive dependence on CNG and to enhance reliability and competition by establishing a second pipeline connection. Since Empire came on line in 1993, RG&E has employed a series of strategies and measures that have addressed the Company's capacity situation. The Company's actions, together with the background of the surplus capacity situation, are described in the March 4, 1999 Upstream Capacity Study

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8 This figure is down from 30,000 DT used in earlier years due to the existence of a more liquid market. See footnote 5, supra.

("Capacity Study") that the Company presented during settlement negotiations in this proceeding. For convenience of reference, relevant excerpts from the Capacity Study are included in Appendix B to this Report.[9] Through the actions described, RG&E has largely eliminated the impact of any unneeded capacity on customers. Moreover, the ratemaking devices instituted pursuant to Commission-approved settlements since 1995 have served to provide additional assurance against adverse impacts to customers.

Although avoiding or limiting the impacts of unused capacity remains a priority, the greater challenge facing RG&E is to deal with the cost implications of retail migration and expiring capacity contracts. At first blush and as a general matter, the expiration of transportation and storage contracts might be regarded as beneficial in that elimination of those obligations would mitigate the total cost of capacity. In other words, to the extent that contracts expire as retail load migrates to marketers, such reduction in contractual obligations would appear to be helpful. As a practical matter, however, the impact is more complicated. With regard to the transportation and storage contracts currently in place, most of the "CNG side" contracts will expire within the next two years, while, on the "Empire side," all of the contracts remain in effect until 2008. Although the commodity cost of gas delivered through the two systems varies, the fixed and variable capacity cost components on the Empire side are generally higher than on the CNG side on a delivered basis to RG&E's city gate. Thus, as the CNG side contracts expire, the cost of transportation, on a unit basis, would be expected to increase. The magnitude of such increase is largely dependent on the remaining throughput as migration continues in future years. In addition to the foregoing concerns, simply allowing all CNG side contracts to expire would present potential difficulties with respect to system operations and reliability, as well as with respect to the possible permanent loss of service to the region.

One apparent solution would be to dispose of some or all Empire side capacity and to retain CNG side assets, thus reducing fixed charges. As will be described in greater detail in this Report, however, such a strategy is fraught with a number of economic and operational

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[9] Pages 1-25 are included in Appendix B. The Capacity Study, as a document prepared and distributed in the course of confidential settlement negotiations, is subject to the protection from disclosure afforded by the Commission's regulations governing settlements (16 NYCRR § 3.9). Since RG&E prepared this document and it does not contain statements of other parties' positions, RG&E may, and hereby does, waive the confidentiality of pages 1-25 as a settlement document. Such waiver, however, is not intended to waive the Company's right to seek Trade Secret protection for the contents of the Capacity Study in accordance with the Commission's Trade Secret regulations (16 NYCRR §§ 6-1.3, 6-1.4).

difficulties. These include the ability of RG&E to renegotiate transportation and storage contract terms and conditions, to maintain appropriate pressures and other operating parameters at both city gates, to match capacity commitments to system requirements as migration and unbundling occur, and, overall, to comply with the Company's obligation to serve under the Public Service Law.

Another possible solution would be to increase utilization of the Empire system as the CNG side contracts expire and thereby mitigate the average unit cost of capacity associated with low throughput. While the RG&E system load factor remains at approximately 25 percent, the load factor on the Empire system could potentially increase from its current level of 16 percent to 36 percent if deliveries through the Mendon city gate were increased. Obviously, however, the ability to increase load factor and reduce unit cost will depend on the alternatives available at any given time, as well as on distribution system operating constraints.

Both the market itself and the reactions it spawns are changing rapidly and will have an impact on capacity requirements. For RG&E, there is continuing uncertainty as to the capacity commitments that will be needed to provide SC 8 (Storage) service, stand-by service pursuant to recent Commission Orders,[10] and Provider of Last Resort ("POLR") service. Such changes make capacity requirements a moving target. While a solution is not impossible; it will undoubtedly be complex.

III. RG&E'S CURRENT PORTFOLIO

RG&E's current portfolio of transportation and storage capacity and natural gas supplies reflects the historical background discussed in the preceding section, as well as the continuing evolution in the market and in industry thinking.

A. <u>Pipeline Capacity</u>

When RG&E determined to establish a second pipeline connection, the original intent was to be able to take approximately half of the total system requirements on CNG and the other half through the new pipeline (Empire). Following the series of delays in the Empire project that thwarted the orderly phase-out of CNG (to the 50 percent level) as Empire was phased in, RG&E

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[10] <u>See</u>, <u>e.g.</u>, Case 97-G-1380, Order Requiring Modifications to Standby Capacity Service, issued October 15, 1999.

was able to reduce its commitment on Empire to 172,500 DT per day, a level somewhat below the amount originally required to provide 50 percent of system requirements on Empire. As a result, RG&E's capacity commitments, before consideration of long-term releases, consist of contracts totaling 172,500 DT per day on the Empire side and 277,690 DT per day on the CNG side.

Appendix D to this Report provides a listing, by city gate, of all of RG&E's transportation and storage contracts. As indicated above, this listing includes commitments that are subject to long-term releases, which, for present purposes, are defined as releases having a term of greater than five months.

Certain CNG side contracts have notice dates that must be complied with to prevent automatic "roll-over" for additional terms. The Tennessee contracts for both Cornwell and South Webster require one-year notice for termination as of October 31, 2000. RG&E provided that notice prior to October 31, 1999. Texas Eastern requires two-year and five-year termination notices, which RG&E gave in 1995 and 1997. For CNG's GSS and GSS II storage and related transportation, either party could give two-year notice of intent to terminate as of the end of the primary term, March 31, 2001. By letter dated March 30, 1999, CNG issued notice to RG&E terminating the Company's two storage contracts as of March 31, 2001. CNG has agreed, however, not to post that capacity pending negotiations with the Company for new storage arrangements.

B. <u>Key Issues Pertaining to Contracts</u>

RG&E's capacity contracts were designed to provide service to the Company's service territory. Because all of the contracts originally predated the advent of capacity release pursuant to FERC Order 636, their terms were not crafted with release transactions in mind. Moreover, in cases where it was necessary to construct additional capacity, "stronger" commitments, such as longer terms, were required to provide a more certain revenue stream to pay for that construction. As might be expected under these circumstances, such features are not conducive to capacity release.

As a general matter, all of the Company's contracts reflect the industry and regulatory philosophy prevailing at the time they were entered into. Long-term capacity contracts were the order of the day in part because reliability of supply was a major concern and in part because new pipeline projects could not achieve regulatory approval or favorable financing terms unless they were supported by long-term contracts. When interstate pipeline service was unbundled by FERC, RG&E received proportionate assignments of CNG's upstream contracts, including a Transco contract extending to 2012. On the Empire side, due to the amount of new construction required to provide service, RG&E was required to enter into contracts with terms of up to 15 years in order to assure income streams sufficient for financing and to meet regulatory requirements for new facilities. Except for relatively inexpensive capacity, most prospective assignees are reluctant to commit to multi-year or permanent releases.

Also as a general and self-evident matter, the value of the capacity available for release reflects the market. Available capacity, particularly on the same pipeline, may depress the value of released capacity. Likewise, the value of RG&E's capacity may be depressed on pipelines where upcoming contract expiration is likely to create additional available capacity.

New service offerings can also have an impact on the marketability of the Company's capacity. On January 7, 2000, for example, ANR, Great Lakes and TransCanada announced the availability of "hub-to-hub" service on their systems between Chicago, Illinois and Dawn, Ontario. The ability of shippers to contract for such service at a total cost of approximately $.19 per DT per day for the current season may be a factor in determining the market value of RG&E's capacity to Dawn.

Certain specific terms of RG&E's contracts limit their "releasability." The Empire contract and tariff, for example, do not expressly permit release of capacity. Likewise, the lack of a bulletin board renders it difficult to effectuate any assignment transactions that might be allowed. Although Empire apparently is willing to allow some form of assignment, RG&E would remain obligated to pay any difference between the variable transportation cost in the contract and any lesser amount the assignee would be willing to pay. Historically, the market price for the Empire capacity has been less than the variable cost. Capacity assignment under these circumstances would simply increase costs to RG&E's customers. RG&E also understands that Empire frequently offers its unsubscribed capacity at discounts below RG&E's contract rates, thus effectively competing against RG&E. A further problem with the Empire contract is that nominating to secondary delivery points is not expressly authorized. Thus, even if assignment were feasible on other grounds, it could only be consummated if delivery occurred at Mendon. Hourly flow restrictions on the Empire system permit only relatively minor variations in hourly takes, thus limiting the value of the capacity for any assignment that might otherwise be possible.

On the ANR system, the rate RG&E pays for transportation service from storage is discounted; but that discount applies only to Farwell as the primary delivery point. Thus, any opportunity to sell gas into other markets using a secondary delivery point results in an incremental cost (i.e., the difference between the discounted rate and the ANR maximum tariff rate, multiplied by the quantity of the proposed release transaction) which must be factored into the overall economics of the proposed transaction. Since release margins are generally thin, this incremental cost often exceeds any potential profit.

Pursuant to earlier mitigation efforts, Great Lakes capacity is subject to an agreement whereby ANR manages that capacity as agent for RG&E. RG&E pays a discounted demand charge and has use of certain quantities during the winter and summer seasons. ANR performs daily nominations and works to arrange releases and remarketing of the capacity that RG&E does not need. Capacity release revenues are shared between ANR and RG&E. As a result of this agreement, however, RG&E has limited control over the Great Lakes capacity.

All of the foregoing matters create challenges either to releasing RG&E's capacity or to achieving substantial financial benefits from such releases.

C. Operational Constraints

One of the significant bases for the Empire project and RG&E's participation in it as a shipper was the operational benefits it would provide to the Company's system. At the time Empire was proposed, RG&E was at the point of determining whether to make a major capital investment to reinforce the west-to-east deliverability of its internal "transmission" system. Because the Empire city gate is located in Mendon, on the eastern side of the RG&E system, it supplanted the need to reinforce the internal system to serve that side of the service area. Now, six years after Empire went into service, the RG&E system cannot function effectively without deliveries at each of the two city gates.

Customers taking service on the Company's 350 PSI maximum allowable operating pressure ("MAOP") system,[11] for example can only be served from CNG. Thus, at no time

[11] The 350 PSI system connects CNG's Caledonia station with the 250 PSI loop that serves much of the remaining system. The 350 PSI MAOP refers to winter pressures.

during the year can the entire RG&E system be served from the Mendon city gate. Even under low load conditions in the range of 75,000 DT per day, Empire cannot supply more than approximately 80 percent of the total system throughput. These limits are illustrated on the graphs contained in Appendix F to this Report.[12] Also, unless waived by Empire, hourly requirements that exceed the Mendon limit of five percent of the daily total can only be served through CNG. On the other hand, as indicated above, there are also times when CNG service alone cannot provide adequate system reliability. As shown in Appendix F, during the heating season (November 1 through April 30), any total system throughput in excess of 270,000 DT per day cannot be served without some deliveries on Empire. During the remainder of the year, any load in excess of 190,000 DT per day requires that at least a portion of the deliveries be made on Empire.

The foregoing operational concerns not only influence daily operations, they also place parameters on the extent to which RG&E can shift its dependence from one side of its upstream capacity system to another, as well as on the extent to which marketers operating within the service area are limited in the location and manner of delivery.

D. <u>Supply Portfolio</u>

Following the issuance of FERC Order 436, RG&E, which had been a full requirements customer of CNG, exercised its rights to obtain a portion of its system requirements from suppliers other than CNG. In doing so, the Company bought part of its system requirements under long-term contracts and part on the spot market. RG&E has actively sought to adapt to the market and to take advantage of new types of service offerings. As the initial long-term contracts expired, RG&E replaced them with shorter-term arrangements and additional swing and peaking contracts. The Company also negotiated reductions in contract quantities and associated reservation fees with nearly all of its gas suppliers and enhanced supply flexibility by converting some contracts for 365-day supply to 151-day seasonal service or 10-day peaking service. Appendix G to this Report shows the Company's current supply portfolio, which includes baseload, swing and peaking contracts with both market area and production area

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[12] Although the Pavilion District is operationally separate from the Rochester District, Pavilion quantities, comprising approximately 5 percent of the total CNG side throughput, are included in Appendix F.

delivery points.[13] These measures have been effective in reducing RG&E's exposure to year-round charges for firm service, while, at the same time, providing a high degree of reliability for the system.

E. **Asset Management Arrangements**

As described in the excerpts from the Capacity Study contained in Appendix B, RG&E has relied on a combination of internal and external resources in its efforts to manage its gas supply and transportation portfolios. Most of these efforts have focused on capacity remarketing and release.

The Company's October 4, 1993 Marketing Agreement with CNG[14] resulted in construction of the "Chambersburg Project" which made possible the permanent assignment of approximately 90,000 DT per day of capacity on the CNG side. Over the three-year period 1995-1998, RG&E's groundbreaking Portfolio Management Agreement with MidCon Gas Services Corp. ("MidCon") assisted the Company in meeting the capacity release objectives of the 1995 Settlement. The Company's similar agreement with Dynegy Marketing and Trade ("Dynegy") has been instrumental in meeting the objectives of the 1998 Interim Settlement[15] and in positioning RG&E to do the same with respect to capacity release under the Proposal.

RG&E has complemented these activities with its own pursuit of other means of reconfiguring its capacity portfolio. As noted in the attached excerpts from the Capacity Study (Appendix B), RG&E has issued a series of Requests for Proposal ("RFP") for its capacity which have helped to provide alternative ways of designing a portfolio that will meet system needs. As described in Section VII B. 2, below, the Company is in the process of evaluating responses received in the "Open Season" announced December 21, 1999. Similarly, on January 5, 2000 RG&E issued an RFP for the supply of system needs, as discussed in Section VII B. 3, below.

F. **Other Cost Mitigation Measures**

RG&E has actively pursued additional opportunities to manage its gas asset portfolio in such a way as to mitigate the cost of providing service to the Company's customers. In the past

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13 Appendix G has been redacted to remove sensitive commercial terms.

14 On February 1, 1995, RG&E and CNG executed a Replacement Marketing Agreement modifying the 1993 Agreement to account for changes in FERC policies with regard to the pricing of compression and related facilities.

six months or so, RG&E has: (1) released 19,400 DT per day of ANR Southeast/Southwest capacity for the winter season, realizing revenues of $520,000; (2) released 9,400 DT per day of Transco capacity for one year (November 1999 through October 2000) for a total of $819,000; (3) terminated the Texas Eastern contract for 12,500 DT per day, avoiding annual demand charges of $1.7 million; (4) evaluated the need for Tennessee capacity and issued a termination notice prior to October 31, 1999, effective as of November 1, 2000, thus avoiding annual demand charges of $6.0 million; (5) participated in resolution of various CNG issues, including development of Delivery Point Operator ("DPO") service and Transportation Cost Rate Adjustment ("TCRA") rate settlement matters; (6) released, through December 1999, approximately .5 BCF of storage capacity and related transportation to marketers pursuant to the Company's SC 8 storage service tariff; and (7) consistent with Commission requirements, developed stand-by service and subsequent release of firm capacity to assure system reliability for the upcoming winter, which is expected to produce revenues of approximately $250,000.

In addition to the foregoing actions, since development of the Proposal, RG&E has taken a number of the specific actions contemplated therein, including: (1) formation of a project team to address capacity cost mitigation measures; (2) retention of the consulting services of Pendulum Energy to provide additional expertise and perspective concerning these matters; (3) analysis of capacity contracts from regulatory, legal, operational and cost perspectives; (4) meetings and correspondence with Empire, ANR, Great Lakes, Union, CNG and Tennessee pipeline representatives to discuss issues and opportunities; (5) meetings with various marketers, to discuss market issues and potential opportunities; (6) meetings with Dynegy, as portfolio manager, to assess opportunities regarding capacity; and (7) meeting with other pipeline customers to discuss capacity remarketing opportunities. Virtually all of these actions will be on-going and RG&E intends to pursue them aggressively.

(Footnote continued from previous page)

[15] Apart from the $11.9 million in capacity release revenues and credits imputed pursuant to the Interim Settlement, Dynegy's efforts resulted in further savings of approximately $3 million.

IV. VALUE OF CURRENT PORTFOLIO

The practicability of efforts to mitigate portfolio costs depends on the value that others will ascribe to RG&E's available assets. Such an evaluation is used to guide the Company's determination of whether various measures are feasible and, ultimately, to select the most promising, cost-effective courses to pursue.

A. Methodology

Determination of the market value of RG&E's transportation and storage assets is extremely sensitive. In the November 29 Report, RG&E provided, under trade secret protection, information on the Company's methodology and the results of its application. In light of the sensitive nature of this information, it is not discussed here.

B. Sensitivities

Various factors have an impact on the market value of RG&E's capacity and, hence, on the Company's ability to mitigate costs through release or assignment of that capacity. First, and most obviously, changes in pipeline rates or rate design will affect RG&E directly where the Company's costs are derived from the tariff. Where special contract rates are in effect, such changes will also have an impact, rendering the contract rates relatively more or less attractive than their tariff counterparts. Second, and far more complicated to assess, underlying changes in the market or in market psychology can produce significant differences in value. New capacity serving the same region served by existing facilities, for example, can lessen RG&E's ability to remarket and/or reduce the price the Company can command.[16] Similarly, the perception by a major pipeline, such as ANR, that capacity will be difficult to remarket can increase the cost of a possible contract restructuring or buy-out.

Examples of external factors that can affect RG&E's capacity costs and the marketability of the Company's capacity include the following: (a) fluctuations caused by weather, psychology, and other market factors that are essentially unpredictable; (b) new pipeline projects that duplicate all or portions of RG&E's routes and, therefore, will tend to impact value until any excess is absorbed; (c) new pipelines serving the Northeast that will also tend to impact value

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16 "Repackaging" of existing facilities and/or services can have the same effect. See discussion of Chicago-to-Dawn "hub-to-hub" service, Section III B, supra.

until the capacity can be absorbed;[17] and (d) changes in cost classification and rate design that could render capacity either more or less valuable.

The valuation of RG&E's capacity could be significantly impacted by rulemaking proceedings and inquiries currently pending at FERC. Two such matters, Docket Nos. RM98-10[18] and RM98-12,[19] which could have a significant impact on the market, are discussed in more detail in Appendix J to this Report.

As the discussion in Appendix J illustrates, these FERC proceedings have the potential to significantly impact the value of RG&E's current transportation capacity. RG&E will continue to monitor these proceedings and to participate in the comment process as permitted. RG&E will review its capacity plans with a view toward accommodating and taking advantage of any opportunities presented by a change in FERC policy.

In addition to the aforementioned rulemakings, RG&E has actively monitored filings at FERC made by the pipelines on which RG&E holds transportation capacity. RG&E intervenes in the potentially significant proceedings and files comments or protests in many of those proceedings that could negatively affect the rates or terms and conditions of service provided by the pipelines. A list of the FERC proceedings in which RG&E has intervened from February 1997 through December 1999 is contained in Appendix K to this Report.

V. PROJECTION OF THE FUTURE

Future capacity needs within RG&E's service territory are dependent on three principal variables: total load to be served; migration to marketers; and system reliability parameters.

A. <u>Load Forecast</u>

RG&E's gas franchise area is a mature retail market that has reached virtually full saturation. As a consequence, no growth from conversions from other energy sources is anticipated. Over the past several years, growth from new construction, expansion of existing

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17 In general, new pipeline projects will have some effect even in their nascent stages. The impact can be expected to be greater as such projects become more certain of completion.

18 <u>Regulation of Short-Term Natural Gas Transportation</u>, Notice of Proposed Rulemaking, FERC Stats. & Regs. ¶ 32,533 (1998)

19 <u>Regulation of Interstate Natural Gas Transportation Services</u>, Notice of Inquiry, FERC Stats. & Regs. ¶ 35,533 (1998)

facilities, and the like has been minimal. For present purposes, therefore, RG&E has assumed no load growth.

B. Migration to Marketers

The speed of migration to service from marketers depends on a number of variables, most of which cannot be predicted or projected with any degree of accuracy. In the Company's Capacity Study (Appendix B), a series of four forecast scenarios were presented, each based on a different assumed migration rate. Collectively, these scenarios were intended to capture what the Company considered a reasonable range of forecasts, the best that could be projected in light of the substantial uncertainties surrounding migration. Since the forecast scenarios were prepared, the market has continued to develop. Based on more current observations and assumptions, therefore, RG&E is providing, as Appendix L to this Report, a revised forecast of migration. In order to simplify this presentation, however, the Company has elected to use one "middle-of-the-road" scenario. The indicated migration rates are consistent with recent actual experience.

C. Balancing Requirements

RG&E maintains a balance between deliveries of gas into its distribution system and consumption of gas by customers connected to the system through the use of CNG no-notice storage and swing supply contracts. As the transportation gas program is currently operated, RG&E is responsible for maintaining this balance between supply and demand both for its own retail customers and for customers served by marketers. As more fully described in the January 28 Filing,[20] RG&E anticipates that competitive suppliers delivering gas to its system will ultimately be required to take responsibility for matching deliveries and consumption on a daily and hourly basis, and that services will soon be available from upstream pipelines that will make this possible. Hence, the Company projects balancing requirements for only its own retail load in the future.

VI. RG&E'S LONG-TERM STRATEGY

RG&E believes that the migration of retail customers to third-party marketer service is inevitable and that the pace of migration in the immediate future will continue to be strong; but

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[20] See Section I E 3.

the pace of migration over the long term will be heavily influenced not only by customer preference, but also by regulatory and social policies. Already, most large customers have migrated to transportation service under SC 3 or to aggregated service under SC 5. Ninety percent of the customers remaining on RG&E's system are residential customers. Although some of those residential customers are likely not to want to switch to marketers, approximately 37 percent are expected to migrate in the next few years. As these customers migrate, the need for RG&E to retain capacity, other than for balancing service, will diminish. Maintaining any amount of capacity beyond that level will become a potentially unnecessary cost and should be avoided, if feasible.

If RG&E is no longer to be responsible for the capacity needs of customers who have migrated, reliability can be maintained by requiring appropriate assurances from marketers that they have adequate firm capacity to ensure delivery of gas to their customers. Assuming that the Commission undertakes such action (e.g., along the lines of specific requirements that marketers have sufficient "quality" capacity to serve their customers),[21] RG&E would continue to aggressively reduce its capacity commitments.

The ideal final state, from RG&E's perspective, would be to eliminate all commitments upstream of the city gate and to purchase all gas required for system supply at the city gate. This approach would reduce fixed costs (i.e., for transportation and storage capacity) and, at the same time, permit maximum flexibility for purchasing supply because RG&E would have no pre-existing obligations to use any particular pipeline path. RG&E considers this approach to be a "win-win" for both the Company and its customers in that it would reduce the risk of stranded capacity costs.

Concerns about the possible loss of upstream pipeline capacity, for either reliability or price reasons, or both, should be ameliorated by the fact that transportation capacity immediately upstream of the city gate, particularly on the CNG side, would have little or no market other than for RG&E and the marketers serving the Company's service area. While the lowest cost capacity upstream of CNG might be marketed elsewhere, the number of interconnections, including new projects, available to serve RG&E's service area should help to maintain a

[21] See, e.g., Case 97-G-1380, Order Concerning Assignment of Capacity, issued March 24, 1999, and subsequent Orders.

competitive market and pricing. The only alternative to this approach, in RG&E's view, would be for the Company to continue to hold upstream capacity to prevent its being marketed elsewhere; but the holding of such capacity would have to be on terms that would protect RG&E and its remaining customers from the impact of migration without corresponding responsibility for unneeded capacity.

In seeking the ideal end-state, RG&E is well aware that certain components of that end-state may take longer to achieve than others. Transportation contracts, for example, may be particularly difficult and costly to restructure. That is why the long-term strategy, as well as the transition strategy (discussed below), must remain flexible.

VII. RG&E'S TRANSITION STRATEGY AND IMPLEMENTATION

A. Goals During Transition

In making the transition to the long-term strategy outlined in the preceding section of this Report, RG&E has identified, and is committed to achieving, four principal goals: maintaining reliability and security of service; offering competitive prices at the city gate; rationalizing contractual obligations to the market; and adjusting to fit the pattern of market migration. Obviously, none of these goals is "new"; RG&E has been pursuing them in one form or another for years, either directly or through the Company's portfolio management initiatives. Likewise, while RG&E considers these goals to be the most critical in the transition process, they should not be understood as excluding consideration of other objectives that may be consistent with them. However, in light of the rapidly changing environment of the natural gas market and the need to address the changes in the market as rapidly as possible, these are the goals upon which RG&E believes it is crucial to focus if the transition is to be successful. At the same time, this strategy will require constant reexamination and reassessment to ensure that it is properly directed.

B. Three-Pronged Strategy

With the aforementioned goals in mind, RG&E developed a strategy comprised of three principal prongs: negotiation with pipelines; holding an "Open Season" to solicit interest in the Company's assets; and development of an RFP for the packaging of supply and capacity into market service for the Company's retail customers. In studying these options, RG&E relied on its own experience (e.g., with pipeline negotiations and RFPs), as well as expert advice from others (e.g., regarding packaged service). In seeking the least cost reliable approach, RG&E believes that a combination of these three elements is likely to be optimal. Accordingly, RG&E has concluded that more or less concurrent implementation of these approaches is desirable. It is important to note that, in the overall process of evaluating each of these developing approaches, RG&E will assess its existing portfolio management approach as an option for achieving the aforementioned goals. Each "prong" is discussed in further detail below.

1. Negotiation with Pipelines.

Adherence to contract terms and conditions, as well as underlying tariff and legal requirements, is critical to the functioning of the natural gas transportation network. RG&E does its utmost to adhere to the letter and intent of its contractual obligations. Many of the Company's existing contracts with upstream pipelines were entered into at a time when long-term certainty and reliability were among the most critical components of a portfolio designed to provide bundled retail service. Changes in the market, however, place less value on long-term certainty and greater value on short-term flexibility, including the ability of an LDC to shed capacity formerly devoted to bundled retail service.

From RG&E's perspective, the ideal solution with regard to capacity would be for the pipelines to agree to restructure their contracts to permit phase-out as retail customers migrate to service from marketers who may obtain their capacity either from the same pipelines or others. Unfortunately, the ideal solution for RG&E is anything but ideal from the pipeline perspective. They regard their contracts with the Company as binding obligations that produce a long-term revenue stream upon which they depend to cover operating expenses and the cost of capital. Achieving an adequate return on investment is particularly important to those pipelines that constructed facilities in order to serve RG&E.

While RG&E respects its contractual obligations and understands the reluctance of pipelines to forgo a "guaranteed" revenue stream, the Company has actively pursued opportunities to modify its obligations to better fit the current needs of its customers. Many of these initiatives pre-date the Company's Proposal in this proceeding. Among the changes RG&E negotiated are: elimination of the "final" ramp-up on the Empire system; a reduction of capacity on the TransCanada/Union segment; and the remarketing of a substantial portion of CNG side capacity in connection with the Chambersburg Project. RG&E has consistently kept the pipelines aware of its ongoing need to restructure its portfolio.

In connection with the Proposal, RG&E renewed its efforts to achieve changes in pipeline contracts. Obviously, the issue of RG&E's strategy in dealings with the pipelines is extremely sensitive from a strategic standpoint and it would be detrimental to the Company's negotiating posture if even the range of possible actions under consideration were disclosed. RG&E identified the options it was exploring and/or pursuing in the November 29 Report subject to trade secret protection. That discussion will not be repeated or updated here. Suffice it to say that the Company will continue to assess such options and pursue those that appear promising.

As indicated earlier, since September 1999, RG&E has had meetings with most of its upstream pipelines to outline the current situation, to discuss the future condition of the market and RG&E's participation in it, and to solicit suggestions from the pipelines as to possible approaches to mitigating capacity costs. The November 29 Report and Supplement Nos. 1 and 2 included discussion of the substance of RG&E's contacts with the pipelines. Copies of relevant documents, including correspondence with the pipelines, were provided in Appendix M to the November 29 Report and in Appendices M-1 and M-2 to Supplement Nos. 1 and 2, respectively. Because of the obvious sensitivity of these contacts, the content of that portion of the November 29 Report and Supplements will not be discussed here. Additional correspondence with the pipelines will be filed separately with a request for trade secret protection.

Without delving into the specific content of exchanges with the pipelines, RG&E can report that the issues have been clearly established and, in each case, further negotiations appear to be warranted. Follow-up meetings will be scheduled and are expected to take place over the next few weeks. RG&E expects that negotiations with the pipelines will be a continuing process and, in all likelihood, will proceed simultaneously with the rate and restructuring negotiations that are contemplated in this proceeding.

2. Open Season to Assign Capacity

Based on past experience with the Open Season (or auction) approach to assignment of capacity, RG&E believes that this option offers an effective means of obtaining the market-determined value for transportation and/or storage assets in the Company's portfolio, either individually or in combinations. RG&E's earlier Open Seasons were widely publicized and, as a consequence, reached a substantial number of current and potential market participants. The sheer number of potential bidders involved in an Open Season may also encourage not only higher bidding for assets, but also taking the assets for longer terms than might be the case in the absence of this level of competition. Moreover, a greater number and broader range of participants is likely to produce more possible combinations of assets than simple posting on individual pipeline bulletin boards. Equally important, the price bidders are willing to pay in an Open Season serves as a market-determined benchmark against which other possible options, including buy-outs and buy-downs and bundled market services discussed in this Report, can be measured.

On December 21, 2000, RG&E initiated an "Open Season for the Long-term or Permanent Release of Firm Transportation and Storage Capacities." The solicitation package, which contains all relevant information for bidding on the Company's capacity, is included in Appendix N to this Report. To ensure maximum participation in the Open Season, RG&E sent the package to approximately 70 companies, including marketers, LDCs and power generators, and advertised to achieve national exposure. The bid due date was January 21, 2000.

RG&E has received bids from over 20 bidders. The Company is currently in the process of evaluating the responses and expects to announce the results and make the necessary follow-up arrangements in time to permit capacity release transactions to take effect by April 1, 2000.

Completion by that date will ensure that capacity required for storage injection will be available to assignees at the beginning of the injection season. It is worth noting that, because most long-term releases for the heating season beginning November 1, 1999 were arranged long ago, the Open Season was not be expected to have any material impact on the current winter's arrangements.

3. Market Service RFP

RG&E has developed a concept, designated the "Market Service Option," that may provide another valuable means of reducing future capacity obligations. Under this approach, those marketers committing to take assignment of a portion of the Company's capacity thereby become eligible to supply gas to the Company's remaining system customers. Moreover, by taking assignment of the Company's capacity, such marketers obtain the right to supply a particular volume of the Company's remaining system load.

Under the Market Service Option, prospective suppliers bid on supplying gas to RG&E's market. Bids are required to be in the form of index plus a premium. The premium is intended to cover costs such as capacity, storage, fuel and administration. Suppliers are required to assume a share of RG&E's capacity portfolio proportionate to the share of the Company's system load to be served. Subject to any overriding reliability concerns, the assumed share of the capacity portfolio can be utilized for any purpose. Awards are made to the lowest evaluated premium bidders. The term of service can be as short as one year or as long as the remaining term of the Company's capacity contracts. The percentage or quantity of RG&E's retail load requirements to be guaranteed to the marketer is proportionate to the quantity of capacity assigned to the marketer, although not necessarily on a one-for-one basis.

One of the major benefits of this approach is that it does not suffer from the perceived shortcomings of mandatory capacity assignment. Marketers are not required to bid on or to take assignment of RG&E's capacity in order to operate in the Company's service area. Bidding on and taking the Company's capacity is only required for those wishing to serve a specific quantity of retail load requirements. Any marketer not wishing to do so remains free to market in the area to migrating customers, as is the case now.

On January 5, 2000, RG&E issued an RFP, based on the Market Service Option concept, to 25 major energy marketers. A copy of the RFP is included in Appendix O to this Report. In issuing the RFP, the Company invited recipients to submit written questions to which the Company subsequently responded. Nearly 100 questions were received and answered; they are contained in Appendix P to this Report. On January 18, 2000, RG&E conducted a pre-bid meeting in Houston, Texas, attended by approximately 15 prospective bidders. At the meeting, RG&E Gas Supply personnel presented and explained the RFP. A copy of the presentation materials is included in Appendix Q to this Report.[22] Most attendees expressed an interest in submitting proposals, which are due February 3, 2000.

RG&E believes that the Market Service Option, as embodied in the RFP, represents an innovative and potentially important way of continuing the transition to a competitive retail market. While RG&E believes that the benefits of such an approach to marketers ought to outweigh any perceived detriment of capacity assignment, the market will be the ultimate test. Should this proposal fail, there are other ways, such as the Open Season, that will serve as a "backstop."

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22 Appendix Q has been redacted to remove sensitive pricing information that has already been included in a trade secret filing.

C. Summary

RG&E proposes to continue its efforts with respect to all three prongs of the transition strategy outlined above. The Company is aware that, to the extent that certain assets are addressed by one of the three options detailed above, those assets will not be available for use in connection with one or both of the remaining alternatives. Thus, rigorous pursuit of these strategies will be an iterative process; it will require constant comparison of benefits and detriments of one option as against the others. Notwithstanding this potential for complication, however, RG&E believes that maintaining all three of these options represents the most promising way of ensuring that the Company can command maximum value for its transportation and storage assets in the market place for the benefit of its customers. Moreover, all three prongs move toward the ideal state of achieving service points closer to the city gate and thereby reducing the exposure of RG&E and its customers to the costs associated with unneeded upstream capacity.

RG&E will continue to provide updated information with respect to the Company's efforts with respect to all three initiatives.

VIII. ACTION BY STAFF AND THE COMMISSION

As approved by the Commission, the Proposal is expressly intended to be a fluid approach to capacity cost mitigation. Such mitigation is not a one-shot effort. It is an iterative process, involving a continuing exchange of ideas among the Company, pipelines, marketers and Staff.[23]

The Proposal expressly recognized the importance of Staff's role in this iterative process by including a requirement that Staff provide a written response to the November 29 Report. Staff did so, as noted earlier, and concluded that the Company . . . had "assembled a reasonable list of options (i.e., the three-pronged approach) to explore for achieving the goal of capacity cost reductions" (Staff Letter at 2). As Staff's letter also recognizes, however, assessment and utilization of the results of the three-pronged approach will require continuing dialogue. RG&E

[23] With the public filing of this Report, RG&E expects to have the benefit of input from other parties as well.

is committed to such ongoing communication and appreciates Staff's recognition of its importance.

IX. CONCLUSION

RG&E takes seriously its obligation to provide least cost reliable service to its customers. In pursuing this goal, the Company has devoted substantial effort and resources to obtaining transportation and storage services that enhance competitive alternatives while maintaining system integrity. For much of this decade, RG&E has faced the challenge of dealing with surplus capacity that arose in connection with the phase-in of the Empire system. Through a combination of measures, the Company has been able to mitigate the impact of that surplus. The challenge to control capacity costs has now shifted away from managing a surplus to dealing with price differentials between different pipeline routes and the risk associated with migration of customers away from bundled retail service.

As this Report demonstrates, RG&E has adjusted to these changing challenges through its actions to date and has outlined a viable multi-dimensional approach to make the transition to the desired end-state. Implementation of the Company's plans is well under way.

RG&E submits that this Report demonstrates that the Company has complied with the requirements set forth in the Proposal, as approved by the Commission, and that the Company has put in motion a program designed to continue the progress made to date and to carry out appropriate plans for dealing with capacity and related issues that will be an even greater challenge in the future.

ROCHESTER GAS AND ELECTRIC CORPORATION

January 28, 2000

APPENDIX A

CITY GATE DELIVERABILITY
VS
PRODUCTION-AREA
AND
STORAGE DELIVERABILITY

ROCHESTER GAS AND ELECTRIC CORPORATION

CITY GATE DELIVERABILITY vs PRODUCTION-AREA AND STORAGE DELIVERABILITY

DESIGN DAY DELIVERABILITY

IN MDT

From Production-Area or Storage	1998-99	1999-00	2000-01	2001-02	2002-03	2003-04	2004-05	2005-06	2006-07	2007-08
Texas Gas	5	15	15	15	15	15	15	0	0	0
Tennesee	49	49	0	0	0	0	0	0	0	0
TRANSCO	0	0	9	9	9	9	9	9	9	9
TETCO	43	31	0	0	0	0	0	0	0	0
ANR SE	14	14	14	0	0	0	0	0	0	0
ANR SW	5	5	34	0	0	0	0	0	0	0
ANR STORAGE	108	108	108	138	138	138	138	138	138	138
CNG STORAGE	142	142	142	0	0	0	0	0	0	0
Total	366	364	322	162	162	162	162	147	147	147
Empire to Mendon City Gate Deliverability	172.5	172.5	172.5	172.5	172.5	172.5	172.5	172.5	172.5	172.5
CNG to Caledonia City Gate Deliverability	277	277	277	0	0	0	0	0	0	0
Empire Reserve Capacity and Market Area Purchase Capability	45.5	45.5	16.5	34.5	34.5	34.5	34.5	34.5	34.5	34.5
CNG Reserve Capacity and Market Area Purchase Capability	38	40	111	-24	-24	-24	-24	-9	-9	-9

Revised 11/24/99

APPENDIX B

UPSTREAM CAPACITY STUDY
(EXCERPTS)

Rochester Gas and Electric Corporation

Gas Rate and Restructuring Project (GRRP)

Upstream Capacity Study

March 4, 1999

CONFIDENTIAL – FOR SETTLEMENT PURPOSES ONLY

Rochester Gas and Electric Corporation
Gas Rate and Restructuring Project (GRRP)
Upstream Capacity Plan

Table of Contents

Gas Rate and Restructuring Project (GRRP) 1

A Introduction 1

Purpose 1

RG&E Gas Business 3

B Background 4

C Customer Migration Experience 10

D Prior Portfolio Restructuring Accomplishments 12

E Description of Portfolio Restructuring Experience 16

F Summary of RG&E's Transportation and Storage Contract Obligations 21

Long-term Resource Plan 26

G Introduction 26

H Portfolio Optimization Methodologies 26

I Model Inputs and Key Assumptions 27

J Retail Demand Forecasts 28

K System Balancing Requirements 31

L Portfolio Design Strategies 34

M Plan Results 39

N Summary Matrices 52

Strategy to Hold New Contracts to a Minimum 55

Potential Contract Changes by Pipeline 55

Quantification of Potential Stranded Costs and a Plan to Manage Them 57

03/04/99
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Rochester Gas and Electric Corporation
Gas Rate and Restructuring Project (GRRP)
Upstream Capacity Plan

Gas Rate and Restructuring Project (GRRP)

A Introduction

Purpose

On August 10 and 11, 1998 Rochester Gas and Electric Corporation ("RG&E") met with Staff and other interested parties to present its Gas Rate and Restructuring Project ("GRRP") Proposal. Effective November 3, 1998, the New York State Public Service Commission ("PSC") issued its Policy Statement Concerning the Future of the Natural Gas Industry in New York State and Order Terminating Capacity Assignment ("Policy Statement"). The Policy Statement and Staff Report and Recommendation dated August 11, 1998 will significantly influence the future of the natural gas business in New York State. Moreover, it will have a significant impact on the future course of RG&E's gas business, its GRRP Proposal, and the transportation and storage capacity contracts that were secured to meet the Company's obligation to serve customer requirements.

The Policy Statement describes the PSC's vision for the gas industry and, in preparation for negotiations, requires each Local Distribution Company ("LDC") to address specific issues including certain ones pertaining to capacity , as set forth below:

- A strategy to hold new capacity contracts to a minimum;

- A quantification of potential stranded costs and a plan to mitigate and manage them

    - At a minimum, the LDC must demonstrate that it has made reasonable efforts to minimize strandable costs in compliance with the Commission's directive in Case 93-G-0932, including the requirements of the Order Clarifying the April 1998 Excess Capacity Filing Requirements, issued September 4, 1997.

In addition, the Policy Statement requires Staff and the utilities to initiate negotiations to develop Company-specific plans to implement the PSC's vision and to initiate collaborative discussions to deal with issues of system operations and reliability, provider of last resort and market power. The PSC also ordered the elimination of mandatory capacity assignment for all utilities as of April 1, 1999.

The purpose of this report and associated capacity plan is to address the capacity issues identified by the PSC, as stated above, based on the following objectives:

- Hold new capacity contracts to a minimum
- Minimize any stranded costs (in the process quantify potential stranded costs and include a plan to mitigate and manage them)
- Maintain adequate capacity to meet RG&E's continuing obligation to serve in a least cost, reliable manner and to support the operational integrity of its distribution system
- Allow for flexibility to accommodate potential migration scenarios
- Develop options and recommendations in a timely manner in accordance with GRRP requirements

Process

In order to address the objectives listed above, RG&E's GRRP Upstream Capacity Team conducted a resource/portfolio plan to identify and evaluate alternative scenarios, based on different levels of customer migration, and resulting load forecasts (for design day, annual and monthly requirements). Further analysis involved the identification of existing and supplemental assets needed to meet customer load and the performance of cost analyses taking into account pipeline and supply source economics to compute projected city gate costs. In addition, risk and reliability factors were evaluated for each scenario and a recommended approach was identified.

RG&E Gas Business

- Service to over 1,000,000 population and over 280,000 customers
- 1998 revenues ~ $275 million
- Retail sendout is 70% (37 BCF normalized for weather) of total throughput
- High percentage (nearly 80%) of retail sendout is residential
- Transport sendout is 30% (17 BCF normalized for weather) of total throughput

B Background

Portfolio Design

RG&E's portfolio was designed in the 1980s as the unbundling of the merchant function was first developing. Beginning in1987, RG&E had contracted for capacity on upstream pipelines, storage and gas supply at the wellhead. Federal Energy Regulatory Commission ("FERC") Order 436 allowed LDCs, like RG&E, to reduce their full-requirements obligations from upstream pipelines and enter into contracts for unbundled services. Prior to 1987, RG&E had a full-requirements (RQ) contract with CNG Transmission ("CNGT"), whereby CNGT would provide daily requirements for RG&E. FERC Order 436 also allowed large industrial customers to procure unbundled gas services from providers other than the LDC. Full unbundling of upstream pipeline services did not occur until 1993, when FERC Order 636 required interstate pipelines to be transporters of gas and to no longer sell bundled services. While taking assignment of transport contracts upstream of RG&E's Caledonia City Gate (CNGT, Texas Gas, Texas Eastern, Tennessee, and Transco), RG&E was also committed to taking capacity contracted on Empire State Pipeline and upstream pipelines (TransCanada, Union, Great Lakes Transmission, and ANR for transportation and storage.) This mixed portfolio of upstream contracts allowed the Company to have competitive service at the City Gate, to no longer be solely connected to CNGT, and to have access to diverse supply basins in the Gulf Coast, Mid-Continent region and western Canada.

Pursuing these benefits had been an important element of the PSC's 1987 Management Audit of RG&E's operations. The Audit Report recommended that RG&E analyze the cost of linking the distribution system directly to Tennessee or other U.S. or Canadian pipelines and, if CNGT refused to provide competitively priced service, to have that link operational, if it were economical, prior to the expiration of RG&E's then-current CNGT contract in 1990.

Although RG&E was able to secure some concessions in settlement negotiations with CNGT (e.g., in the 12 months ending May 30, 1989, RG&E was able to purchase more than 31% of its total system throughput from sources other than CNGT), such concessions did not address the Management Audit concern about exclusive reliance on CNGT for transportation. In seeking an alternative for transportation, however, RG&E determined that reliance on another "incumbent" pipeline, such as Tennessee, would do little to achieve the principal objectives of a second pipeline connection. Instead, RG&E opted to become a shipper on Empire, for which a Public Service Law Article VII application had been filed in 1988 and which received a Certificate of Environmental Compatibility and Public Need in early 1991.

In studying the Empire project, RG&E had concluded that it would offer much needed competition to the incumbent pipelines, access to important supply basins in the mid-continental U.S. and Western Canada, and enhanced reliability. The latter benefit would result not only from the geographical diversity of supply, but also from a new physical interconnection in the Town of Mendon at a point where maintaining pressure would become increasingly difficulty in the future, absent reinforcements to RG&E's own "transmission" system.

In deciding to ship approximately one-half of its system requirements on Empire, RG&E had to contract with pipelines, gas suppliers and providers of storage upstream of Empire. At the same time, RG&E had to arrange for the reduction, or "ramping down," of commitments on the CNGT system to correspond to the "ramping up" of new service.

Initially, the ramping down of CNGT service and the ramping up of Empire service were planned to occur over a three-year period on the assumption that Empire and necessary upstream facilities would be in service by November 1, 1990. Through a combination of regulatory delay, opposition by incumbent pipelines and the resultant uncertainties surrounding construction, RG&E was not in a position to ramp down its CNGT contracts (i.e., by giving required notices) at the same time Empire went into service in the fall of 1993. Likewise, there was little interest on the part of other prospective shippers on the CNGT system in taking RG&E's combined package of storage and transportation capacity; substantial portions would have been stranded.

The foregoing factors combined to produce the surplus of upstream capacity that faced RG&E when Empire went on line in November 1993. At that time, RG&E's system design day was approximately 450,000 Dt, of which approximately 400,000 D+ was covered by firm transportation arrangements on the CNGT system. As a result of the inability to ramp down those CNGT system commitments, RG&E's total firm transportation capacity commitments were as follows:

Empire System	172,500 Dt/d
CNGT System	390,000 Dt/d
TOTAL	562,500 Dt/d

These figures exclude a subsequent ramp-up of 55,000 Dt/d that was scheduled to occur on the Empire system on November 1, 1994.

RG&E's capacity surplus was, of course, one of the principal matters addressed in the 1995 Settlement that expired on October 31, 1998.

City Gate Deliverability:

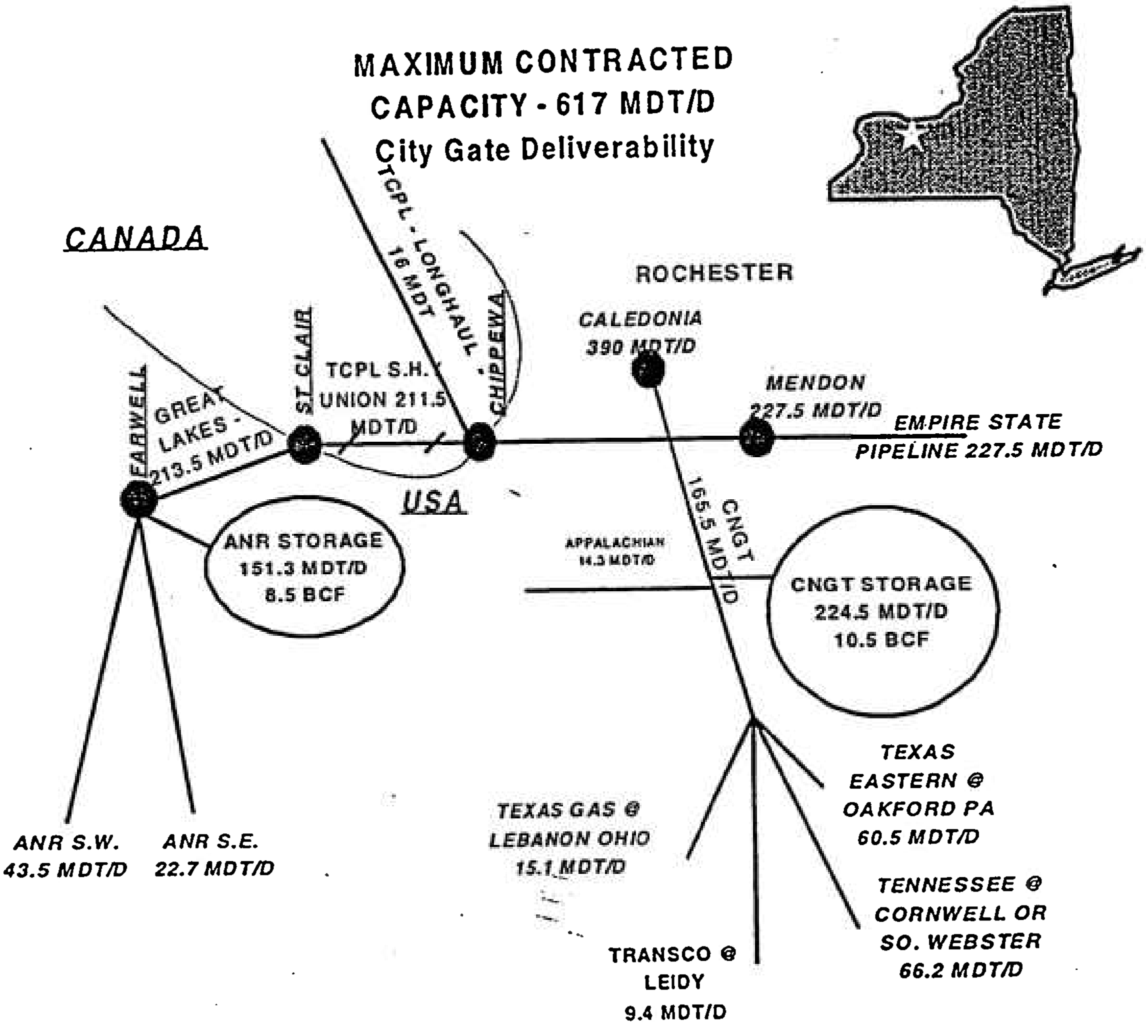

Figure 1 - November 1993 Capacity Map Before Capacity Releases

The design of RG&E's portfolio is significantly impacted by load characteristics of its market. The load duration curve and daily sendout pattern shown in the next two figures (DT/day) illustrate the dramatic difference in gas usage between heating and non-heating season; the winter demand for a design day is 15 times greater than the demand in the summer months. These load curves are utilized, among other things, to determine the capacity holdings and other resources needed to serve design day load.

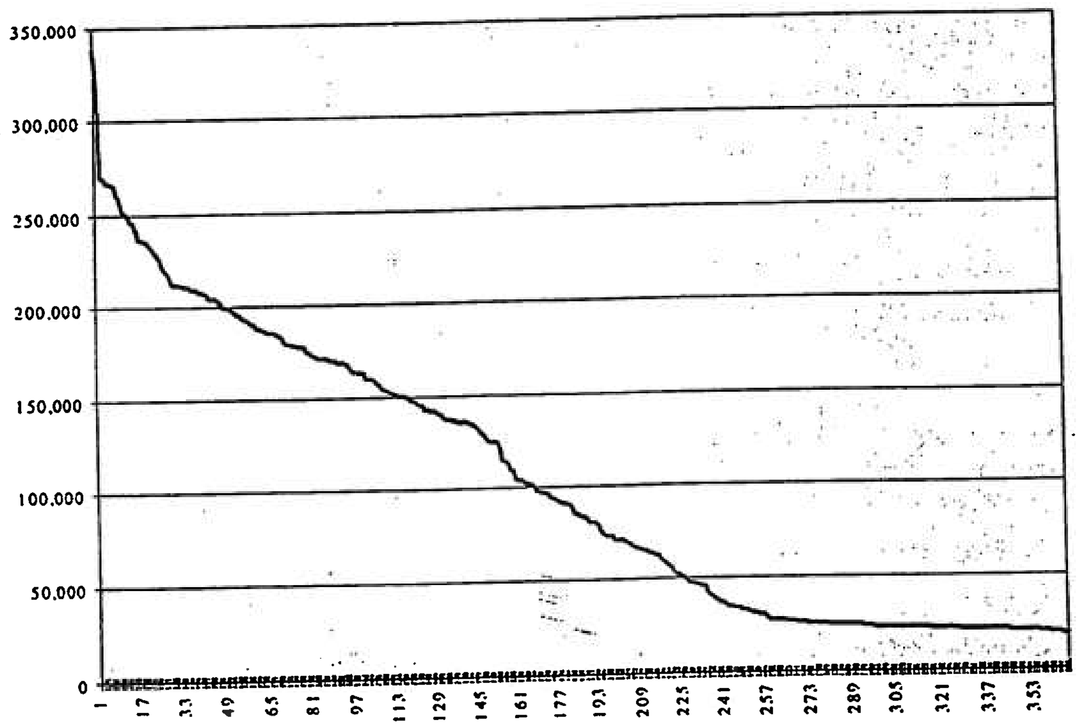

Figure 2 - Typical Load Duration Curve

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Upstream Capacity Plan

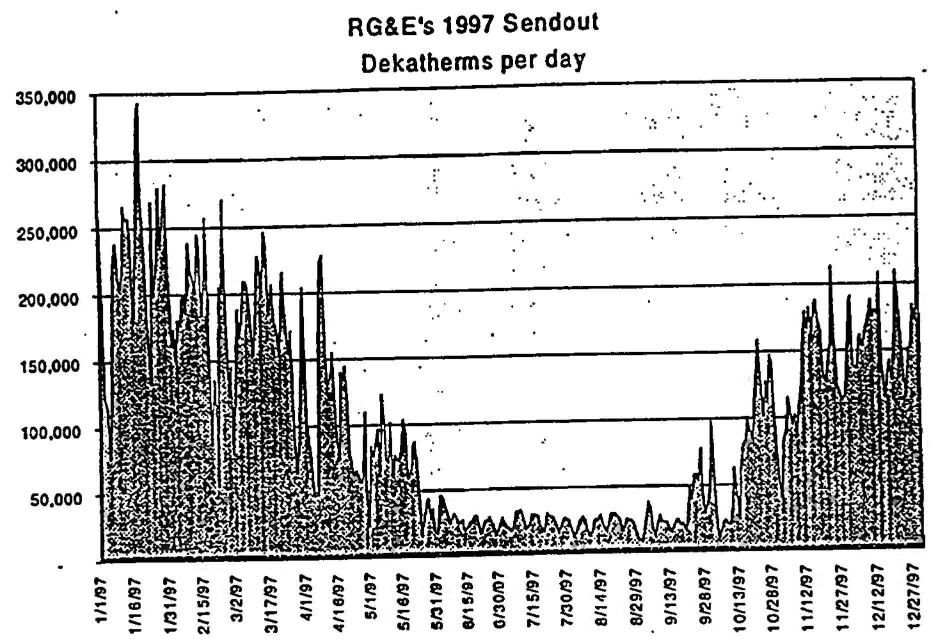


Figure 3 - Chart of 1997 Daily Sendout Pattern

C Customer Migration Experience

- 31% migration of throughput since 1985
- 2% migration of retail load from November 1996 – October 1998 under aggregation program
- 3% migration of retail load from November 1998 – February 1999

RG&E has experienced migration of industrial customers since 1985. Currently, these customers ship 31% of the annual system throughput. The larger commercial and industrial customers have taken the opportunity to procure service through marketers. Larger cost advantages existed several years ago because of the savings appreciated through taxes, the market value of capacity, and pricing not being as liquid as it is today.

In November 1996 RG&E implemented its aggregation program. This program was responsive to PSC Opinion No. 94-26, which called for LDCs to offer programs that allowed all customers the right to buy upstream services through other providers. It also urged the LDCs to unbundle their rates for all of their upstream services, such as balancing, storage, and capacity. Since the implementation of this program, the Company has experienced migration of approximately 5% of its retail throughput to transport sales.

Figure 4 below depicts this load migration showing actual data for 1985 through 1998, and forecasted data for 1999.

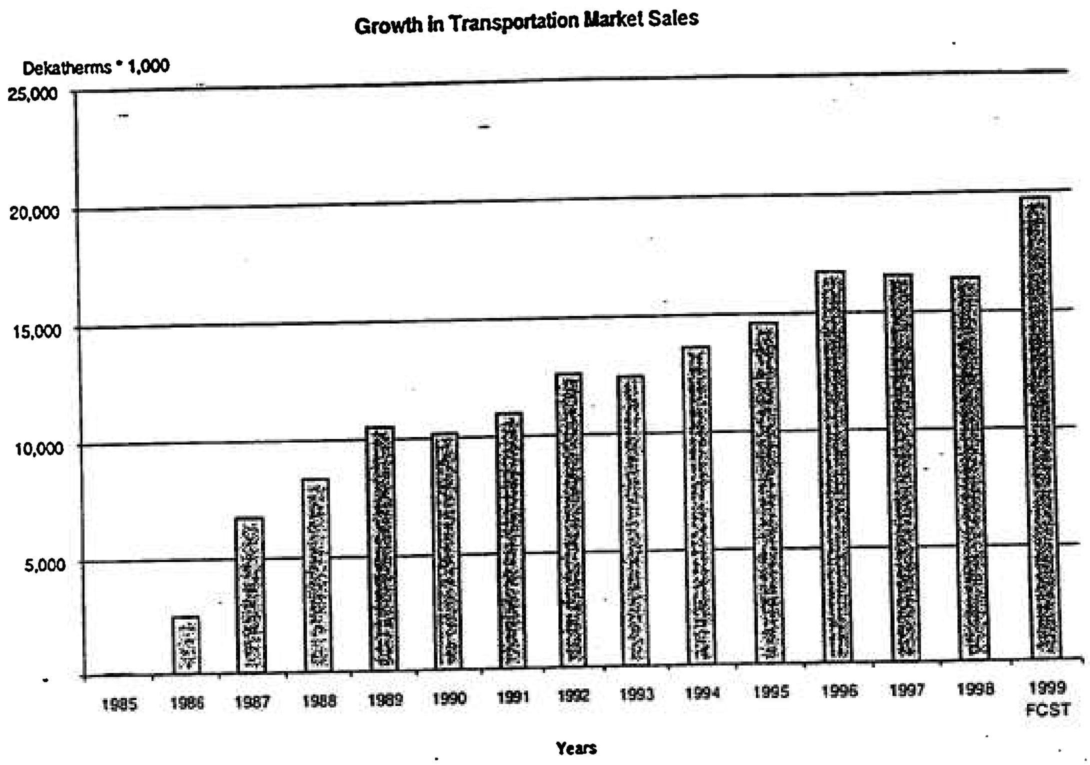


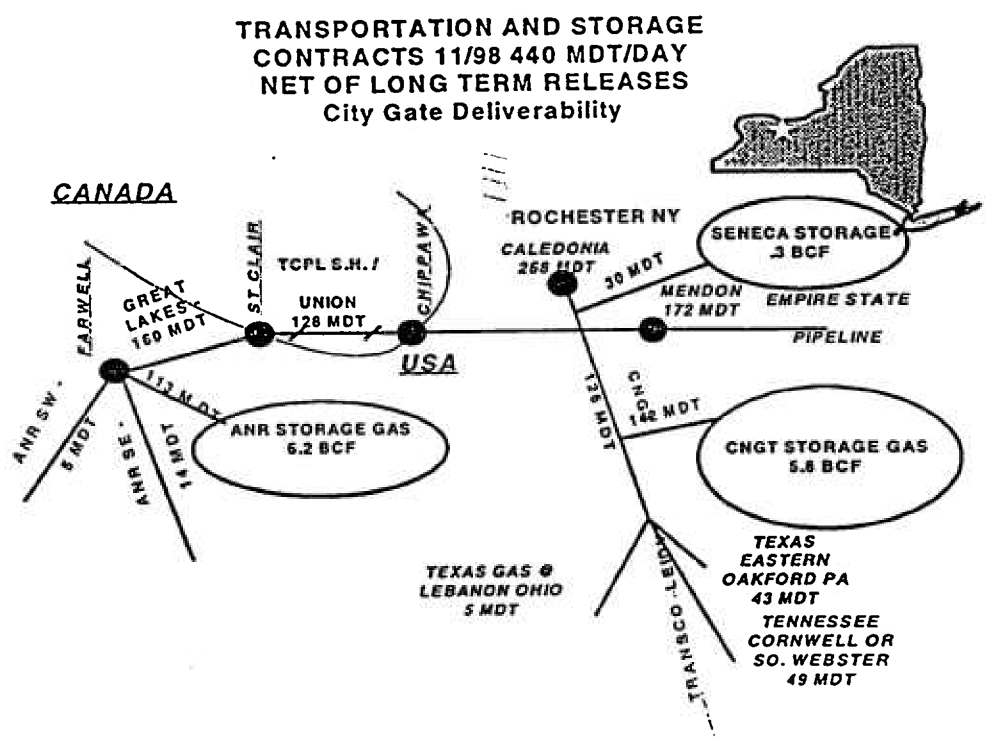
Figure 4 – Actual Annual Transportation Sales*

*not adjusted to normalized weather

D Prior Portfolio Restructuring Accomplishments

RG&E has managed a complex gas transportation and storage portfolio since 1993. Through several cost mitigation efforts undertaken since 1995, the Company has successfully reduced transportation and storage expenses by approximately 30% from their 1995 levels, from approximately $110 million to $70 million (net of all releases of capacity). The mitigation efforts used to reduce these expenses have included restructuring the portfolio through selling capacity (long-term or permanent releases), buying down contracts, turning back capacity through expansion project opportunities, utilizing portfolio management services, and effectuating capacity releases (short-term releases). RG&E's current capacity portfolio (net of releases for periods of greater than one year) is depicted below.

Figure 5 - Current Map of Capacity



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Upstream Capacity Plan

Date	Event	Method	MDT Reduction	Annual Demand Reduction $ Millions
1994 - April 1995	CNG storage contract restructured	Remarketing agreement	1 BCF	$ 1.8
November 1995	Transco 4 year release Chambersburg Project CNG Tennessee Texas Eastern	Capacity Release Remarketing Agreement/ Buyout (permanent releases)	9.6 Mdt/d Various	1.3 10.4
April 1996	Empire, ANR and GLTC contracts restructured Deferred ramp-up Eliminate contract ramp-up	Capacity releases and Buyout	55 Mdt/d	Up to 11.3
November 1996	Termination of TCPL longhaul contract Texas Gas 3 year release ANR SE/SW long term relinquishment CNG release	Capacity RFP & RG&E open season	Various	10.4
December 1997	TCPL release	Capacity release	20 Mdt/d	0.8
February 1998	TCPL turnback	Pipeline open season	1 Mdt/d	-
May 1998	Proposed CNGT Turnback	Pipeline turnback	21.7 Mdt/d	1.5
June 1998	Proposed GLTC reduction - cancelled	Turnback program per FERC expansion requirements	31.9 Mdt/d	

Figure 6 - Chronological Listing of Reduction of Assets

The Company's City Gate deliverability both historically and projected (based on existing contract expiration dates) is shown below.

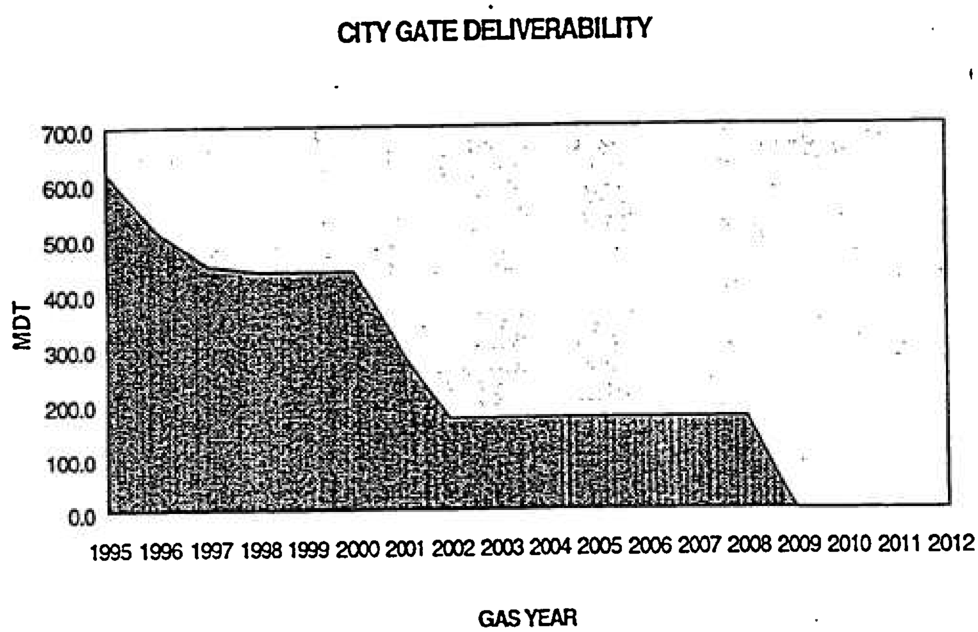

Figure 7 - City Gate Deliverability

The Company's historical and projected transportation and storage capacity costs are shown below. Such costs are based on existing contract expiration dates and take into account prior restructuring initiatives, including long-term capacity releases.

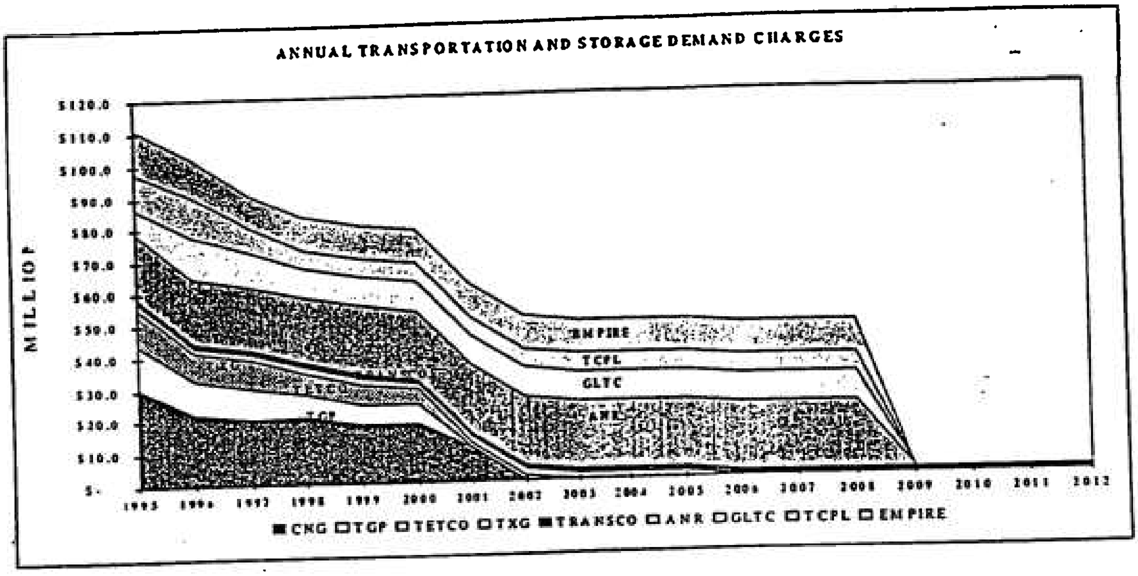

Figure 8 - Transportation and Storage Capacity Costs

IN MILLIONS $

GAS YEAR ENDING October 31,	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
PIPELINE																		
CNG					$ 21.3	$21.3	$10.4	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TGP					$ 5.9	$ 5.9	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TETCO					$ 6.8	$ 4.8	$ 1.5	$ 1.5	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TXG					$ 1.8	$ 1.8	$ 1.8	$ 1.8	$ 1.8	$ 1.8	$ 1.8	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TRANSCO					$ 1.3	$ 1.3	$ 1.3	$ 1.3	$ 1.3	$ 1.3	$ 1.3	$ 1.3	$ 1.3	$ 1.3	$ 1.3	$ 1.3	$ 1.3	$ 1.3
ANR					$ 21.3	$21.3	$21.3	$ 21.3	$21.3	$21.3	$21.3	$21.3	$21.3	$21.3	$ -	$ -	$ -	$ -
GLTC					$ 9.0	$ 9.0	$ 9.0	$ 9.0	$ 9.0	$ 9.0	$ 9.0	$ 9.0	$ 9.0	$ 9.0	$ -	$ -	$ -	$ -
TCPL					$ 5.8	$ 5.8	$ 5.8	$ 5.8	$ 5.8	$ 5.8	$ 5.8	$ 5.8	$ 5.8	$ 5.8	$ -	$ -	$ -	$ -
EMPIRE					$ 10.4	$10.4	$10.4	$ 10.4	$10.4	$10.4	$10.4	$10.4	$10.4	$10.4	$ -	$ -	$ -	$ -
CAPACITY RELEASE					$(11.9)	$(8.2)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
TOTAL	$111.5	$ 85.0	$ 76.5	$ 69.2	$ 72.7	$70.5	$61.6	$ 51.2	$49.7	$49.7	$49.7	$47.9	$47.9	$47.9	$ 1.3	$ 1.3	$ 1.3	$ 1.3
	Actual				Projected													

Assumptions:
Net of permanent and short term capacity releases
Projected values based on January 1999 tariff rates

Figure 9 - Total Contracted Costs through 2008

03/04/99

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E Description of Portfolio Restructuring Experience

Capacity Release

Since the implementation of FERC Order 636, capacity holders have been allowed to post unused capacity on electronic bulletin boards, notifying other shippers that they could bid for this capacity. This type of posting in the secondary market has increased the liquidity of pipeline segments. However, it also is limiting in that FERC currently does not allow capacity holders to receive more than maximum tariff rates for the capacity, even though market conditions may warrant it (i.e., high demand and low supply of capacity, coupled with another party willing to pay greater than the maximum tariff rate).

The term of capacity release is flexible, including monthly, seasonal, and multi-year periods. It should be noted that under temporary releases of capacity, the original capacity holder (e.g., RG&E) still retains the financial responsibility for the capacity in the event that the replacement shipper defaults on its obligations.

As shown on Figure 6 above, RG&E has generated millions of dollars of annual savings through capacity release transactions. Capacity release values fluctuate because they are affected by changing market conditions (i.e., supply and demand.) It must be remembered that, when RG&E's system demand is low, that of the rest of the market is also relatively low and other holders of capacity are often releasing as well.

It should also be noted that FERC is in the process of reviewing its rules and regulations with respect to capacity release, as well as other matters pertaining to interstate transportation. RG&E is actively following these proceedings to have a say in any changes that may impact our business practices.

Finally, there is no opportunity to release Empire State Pipeline capacity since Empire is an intrastate pipeline under the jurisdiction of the PSC and therefore is not subject to FERC capacity release rules and regulations.

Remarketing Agreement

In the fall of 1993 RG&E entered into a remarketing agreement with CNGT. This agreement gave CNGT the right to market approximately 100,000 DT/day of CNGT and upstream pipeline capacity and storage. This was one of the efforts the Company took to reduce its contractual obligations, subsequent to FERC Order 636 and the start-up of the Empire State Pipeline. This agreement pertains to a project known as Chambersburg whereby facilities were built and improved on the CNGT and Texas Eastern systems, which allowed capacity originally designed to flow gas to Rochester, to be utilized by mid-Atlantic customers. Several mid-Atlantic customers took long-term and subsequent permanent assignment of approximately 90,000 DT/day of cumulative capacity on CNGT, Texas Eastern, and Tennessee pipelines.

RG&E paid CNGT $10 million toward the cost of facilities improvements that were needed to accommodate the reassignment of capacity. This payment allowed CNGT and Texas Eastern to go forward without applying for rolled-in rate treatment of the project. Since the project was for the purpose of serving only a handful of customers, proposing rolled-in rate treatment had a low probability of success and would likely have delayed the project and ultimate assignment of capacity.

RG&E and its customers are realizing approximately $10 million annually in reduced demand charges due to the assignment of the 90,000 DT/day of transportation and of storage capacity.

Portfolio Management

Beginning in June 1995 RG&E contracted with MidCon Gas Services to provide portfolio management services. This was the first time comprehensive portfolio management services on such a large scale had arranged for an LDC. Through an extensive RFP process, the Company evaluated approximately 15 proposals, which ultimately concluded in the execution of a definitive agreement with MidCon Gas Services.

The primary objective of utilizing a portfolio manager was to work with a marketing firm that had a national marketing presence and a working knowledge of RG&E's upstream asset base in order to optimize the portfolio to achieve maximum savings.

RG&E's experience confirms the benefits of working with an organization that has access to the markets and supply basins linked to the ten pipelines that serve RG&E. With more than three years of portfolio management experience behind us, we have been able to try different services and incentives to identify what works best for all parties involved.

In July 1998, RG&E secured Dynegy Marketing and Trade as the new portfolio manager for a period of two years. Dynegy will act on RG&E's behalf, nominating natural gas to storage and City Gate, releasing unused pipeline capacity, and optimizing storage and transportation assets to bring greater value to RG&E and its customers.

Portfolio Reconfiguration

RG&E's Gas Supply Management team continues its efforts in long-range planning for optimizing the use of gas assets. This process began primarily as long-term releases and continued in 1995 to encompass a sophisticated Open Season capacity offering to 69 companies requesting a bid package in 1996. Nearly half of the companies responded with offers for RG&E's capacity. RG&E's proposal was noted in *GAS DAILY* since RG&E was the first LDC in the nation to make an RFP of this nature. As a result of this effort, RG&E negotiated several permanent and long-term assignments of transportation and storage capacity. In 1997, RG&E again issued an RFP requesting valuation of its winter transportation capacity. As a result of the 1997 RFP process, RG&E has become more active in temporary assignment of Great Lakes and TransCanada capacity for the winter season.

The RG&E team learned numerous lessons through these experiences. The most significant lesson is that the system can be configured in many ways. With two pipelines serving RG&E City Gates and a variety of pipelines upstream of those two, there are numerous alternatives and services that affect RG&E's asset portfolio. As a result of their experiences, RG&E has reshaped its assets by replacing long haul transportation and storage capacity intended to meet a design day numerous times during a winter with shorter term peaking and swing services at lower overall costs.

RG&E did not stop at reshaping its transportation portfolio, but aggressively negotiated lower reservation fees from nearly all gas suppliers. In addition, to achieve greater flexibility and lower costs, RG&E was able to convert some contracts for 365-day term supply service into a 151-day service.

RG&E's portfolio reconfiguration initiatives have achieved millions of dollars of annual savings as highlighted in Figure 6 above.

Buyout/Buydown

One mechanism to reduce contracted capacity is to buy out the capacity at negotiated value. RG&E has successfully reduced pipeline capacity on TransCanada/Union through a buyout program. Generally, pipelines are reluctant to give up a guaranteed revenue stream from enforceable contracts.

Pipeline Turnback

Several pipelines (Great Lakes, TransCanada, Tennessee and CNGT) have surveyed the market to establish interest in turning back capacity. Of these pipelines, only Great Lakes, CNGT and TransCanada offered turnback programs at maximum tariff rates. Where feasible at maximum tariff rates, RG&E has offered to turn back capacity to these pipelines, as summarized in Figure 6.

F Summary of RG&E's Transportation and Storage Contract Obligations

Capacity contract arrangements include capacity for pipeline and storage transportation. The primary benefit is the dedication of a pipeline's assets/resources to assure operational reliability for RG&E and its customers. Firm service supports an LDC's "obligation-to-serve" requirement. RG&E's capacity contracts have terms ranging up to 19 years. These contracts obligate RG&E to pay fixed demand charges, variable costs and other FERC surcharges (e.g., transition costs).

Services offered by the pipelines vary; they include firm transportation, and storage services designed with different levels of flexibility. For example, CNGT offers a no-notice storage service whereby any city gate imbalance automatically flows into or out of storage. ANR, on the other hand, only offers a nominating storage service (requiring daily nominations), since it is three pipelines away from RG&E's City Gate.

Rochester Gas and Electric Corporation
Gas Rate and Restructuring Project (GRRP)
Upstream Capacity Plan

Transportation and Storage Contracts	Expiration Date	Contractual MDQ MDT/d
CNG System (Caledonia City Gate)		
Seneca firm Storage	September 1999	30
CNGT firm transportation	March 2001	126
CNGT firm storage	March 2001	142
TGP firm transportation	October 2000	49
Texas Gas firm transportation	October 2005	15
TEXAS EASTERN firm transportation	October 1999/2000	43
Transco firm transportation	October 2012	9
Empire System (Mendon City Gate)		
Empire firm transportation	October 2008	172
TransCanada firm transportation	"	137
Great Lakes firm transportation	"	213
ANR Pipeline firm transportation	"	65
ANR firm storage	"	151

Pipeline Contract	Notification Date	Expiration Date
Empire 95001	None	10/31/08
ANR 18750	None	10/31/08
ANR 25850	None	10/31/08
ANR 25900	None	10/31/08
ANR 68750	None	10/31/08
ANR 75850	None	10/31/08
ANR 33000	None	10/31/08
TCPL 2939	None	10/31/08
TCPL 2937	None	10/31/08
TEXAS EASTERN 800370R1	Issued 10/31/95	10/31/00
TEXAS EASTERN 800248	Issued 10/29/97	10/31/99
CNGT 300084	3/31/99	3/31/01
CNGT 400055	3/31/99	3/31/01
Seneca Storage	7/1/99	9/14/99
TGP 820	10/31/99	10/31/00
TGP 3915	10/31/99	10/31/00
CNGT 100021	3/31/00	3/31/01
CNGT 700018	3/31/00	3/31/01
CNGT 200103	3/31/00	3/31/01
TXGAS 3943	10/31/04	10/31/05
GLGT FT056	4/30/06	10/31/08
GLGT FT067	10/31/07	10/31/08
TCPL 2939	10/31/07	10/31/08
TCPL 2937	10/31/07	10/31/08
Transco 6506	10/31/11	10/31/12

Figure 10 - Contract Notification Schedule

Rochester Gas and Electric Corporation

CITY GATE TRANSPORTATION AND STORAGE ASSETS (Contracted Volumes Adjusted for Releases/Assignments)

DEKATHERM - VOLUMES STATED AT CNGT INTERCONNECTS

CONTRACT	CITY GATE	PIPELINE	EXP. DATE	RATE SCH.	RECEIPT POINTS	DELIVERY POINTS	ZONE OR LEG	11/1/98 - 3/31/99 MDQ	11/1/99 - 3/31/00 MDQ	4/1/01 - 10/31/05 MDQ
100021	CNG	CNGT	3/31/01	FTNN	Cornwell	Caledonia City Gate		30,025	30,025	
100021	CNG	CNGT	3/31/01	FTNN	South Webster	Caledonia City Gate		18,326	18,326	
100021	CNG	CNGT	3/31/01	FTNN	Oakford	Caledonia City Gate		42,666	42,666	
100021	CNG	CNGT	3/31/01	FTNN	Lebanon	Caledonia City Gate		4,993	14,766	
100021	CNG	CNGT	3/31/01	FTNN	Leidy - Transco	Caledonia City Gate		9,413	9,413	
200103	CNG	CNGT	3/31/01	FT	Leidy - Tetco	Caledonia City Gate		20,500	20,500	
						Total CNG FT/FTNN		125,923	135,696	
700018	CNG	CNGT	3/31/01	FTNNGSS	Storage	Caledonia City Gate		141,994	141,994	
	CNG	NYSEG	9/14/99			Injection 20 days		15,000	30,654	
	CNG	NYSEG	9/14/99			Storage Capacity		300,000		
	CNG	NYSEG	9/14/99			Withdrawal 10 days		30,000	136,726	
300084	CNG	CNGT	3/31/01	GSS		Injection - Less than 50% - 180 days		30,654	30,654	
300084	CNG	CNGT	3/31/01	GSS		Injection - More than 50% - 214 days		25,784	25,784	
300084	CNG	CNGT	3/31/01	GSS		Storage Capacity		5,517,809	5,517,809	
300084	CNG	CNGT	3/31/01	GSS		Withdrawal MDWQ		136,726	136,726	
400055	CNG	CNGT	3/31/01	GSS II		Injection - Less than 50%		1,990	1,990	
400055	CNG	CNGT	3/31/01	GSS II		Injection - More than 50%		1,674	1,674	
400055	CNG	CNGT	3/31/01	GSS II		Storage Capacity		358,191	358,191	
400055	CNG	CNGT	3/31/01	GSS II		Withdrawal MDWQ		5,268	5,268	
820	CNG	Tennessee	11/1/00	FT	Various Meters	CNGT @ Cornwell	0/100	9,754	9,754	
820	CNG	Tennessee	11/1/00	FT	Various Meters	CNGT @ Cornwell	1/100	1,000	1,000	
820	CNG	Tennessee	11/1/00	FT	Various Meters	CNGT @ Cornwell	1/500	13,519	13,519	
820	CNG	Tennessee	11/1/00	FT	Various Meters	CNGT @ Cornwell	1/800	6,452	6,452	
3915	CNG	Tennessee	11/1/00	FT	Various Meters	CNGT @ South Webster	0/100	3,282	3,282	
3915	CNG	Tennessee	11/1/00	FT	Various Meters	CNGT @ South Webster	1/500	9,795	9,795	
3915	CNG	Tennessee	11/1/00	FT	Various Meters	CNGT @ South Webster	1/800	5,677	5,677	
						Total Tennessee		49,479	49,479	
800248	CNG	TETCO	10/31/99	FT	Various	CNGT @ Oakford	M1-M2	12,500		
800370 R1	CNG	TETCO	10/31/00	FT	Various	CNGT @ Oakford	M1-M2	31,162	31,162	
						Total TETCO		43,662	31,162	
3943	CNG	Texas Gas	10/31/05	FT	Various	CNGT @ Lebanon, OH	Zone 1	2,252	2,252	2,252
3943	CNG	Texas Gas	10/31/05	FT	Various	CNGT @ Lebanon, OH	Zone SL	2,858	12,858	12,858
						Total Texas Gas		5,110	15,110	15,110
6506	CNG	Transco	10/31/12	FT	Various	CNGT @ Leidy	Zone 3		9,106	9,106
6506	CNG	Transco	10/31/12	FT	Various	CNGT @ Leidy	Zone 4		201	201
						Total Transco		-	9,307	9,307
CITY GATE TOTALS (CNG FTNN + FTNNGSS)								267,917	277,690	-

Figure 11 - East Side Contract Summary

Rochester Gas and Electric Corporation

CITY GATE TRANSPORTATION AND STORAGE ASSETS (Contracted Volumes Adjusted for Releases/Assignments)
DEKATHERM - VOLUMES STATED AT INTERCONNECTS

CONTRACT	CITY GATE	PIPELINE	EXP. DATE	RATE SCH.	RECEIPT POINTS	DELIVERY POINTS	ZONE OR LEG	11/1/98 - 3/31/99 MDQ	4/1/01 - 10/31/08 MDQ
18750	EMPIRE	ANR	10/31/08	FTS-1	Production	Farwell	SE	14,265	22,470
68750	EMPIRE	ANR	10/31/08	GF-1	Gathering	Gathering	SE	14,265	22,470
25850	EMPIRE	ANR	10/31/08	FTS-1	Production	Farwell	SW	5,000	43,000
25900	EMPIRE	ANR	10/31/08	FT-1	Storage	Farwell		111,600	151,200
33000	EMPIRE	ANR	10/31/08	FSS	Storage Capacity			6,228,915	8,432,435
33000	EMPIRE	ANR Storage	10/31/08	FSS		Injection		31,203	42,162
33000	EMPIRE	ANR Storage	10/31/08	FSS	Withdrawal	Withdrawal		113,465	153,317
FT056	EMPIRE	Great Lakes	10/31/08	FT	Farwell	St. Clair		104,339	A)
FT067	EMPIRE	Great Lakes	10/31/08	FT	Farwell	St. Clair		56,222	B)
						Total Great Lakes		160,561	-
SH 2939	EMPIRE	TCPL - SH	10/31/08	FT	St Clair	Chippawa		102,821	101,793
SH 2937	EMPIRE	TCPL - SH	10/31/08	FT	St Clair	Chippawa		25,714	35,357
						Total TCPL		128,535	137,150
95001	EMPIRE	Empire State PL	10/31/08	FT	Chippawa	Mendon City Gate		172,500	172,500
CITY GATE TOTALS (EMPIRE STATE PL)								172,500	172,500

A) 104,339 Winter/[illegible] Summer B) 56,222 Winter/31,910 Summer

Figure 12 - West Side Contract Summary

APPENDIX D

TRANSPORTATION
AND
STORAGE CONTRACTS

Rochester Gas and Electric Corporation
Summary of Transportation and Storage Contracts
November 1, 1999

Pipeline Contract	Termination Notification Date	Expiration Date
ANR 18750	NONE	10/31/08
ANR 25850	NONE	10/31/08
ANR 25900	NONE	10/31/08
ANR 33000	NONE	10/31/08
ANR 68750	NONE	10/31/08
ANR 75850	NONE	10/31/08
CNGT 100021	3/31/00	3/31/01
CNGT 200103	3/31/00	3/31/01
CNGT 300084	ISSUED 3/30/99	3/31/01
CNGT 400055	ISSUED 3/30/99	3/31/01
CNGT 700018	3/31/00	3/31/01
EMPIRE 95001	NONE	10/31/08
GLGT FT056	4/30/06	10/31/08
GLGT FT067	10/31/07	10/31/08
TCPL 2937	NONE	10/31/08
TCPL 2939	NONE	10/31/08
TEXAS EASTERN 800370R1	ISSUED 10/31/95	10/31/00
TGP 3915	ISSUED 10/28/99	10/31/00
TGP 820	ISSUED 10/28/99	10/31/00
TRANSCO 6506	10/31/11	10/31/12
TXGAS 3943	10/31/04	10/31/05

Rochester Gas and Electric Corporation

RGE

CITY GATE TRANSPORTATION AND STORAGE ASSETS (Contracted Volumes Adjusted for Releases/Assignments)

DEKATHERM - VOLUMES STATED AT CNGT INTERCONNECTS

CONTRACT	CITY GATE	PIPELINE	EXP. DATE	RATE SCH.	RECEIPT POINTS	DELIVERY POINTS	ZONE OR LEG	11/1/99 - 3/31/00 MDQ	4/1/00 - 10/31/00 MDQ	11/1/00 - 3/31/01 MDQ	4/1/01 - 10/31/05 MDQ	11/1/05 - 10/31/12 MDQ
100021	CNG	CNGT	03/31/01	FTNN	Cornwell	Caledonia City Gate		30,025	30,025	30,025		
100021	CNG	CNGT	03/31/01	FTNN	South Webster	Caledonia City Gate		18,326	18,326	18,326		
100021	CNG	CNGT	03/31/01	FTNN	Oakford	Caledonia City Gate		42,666	42,666	42,666		
100021	CNG	CNGT	03/31/01	FTNN	Lebanon	Caledonia City Gate		14,766	14,766	14,766		
100021	CNG	CNGT	03/31/01	FTNN	Leidy - Transco	Caledonia City Gate		9,413	9,413	9,413		
200103	CNG	CNGT	03/31/01	FT	Leidy - Tetco	Caledonia City Gate		20,500	-	20,500		
						Total CNG FT/FTNN		135,696	115,196	135,696		
700018	CNG	CNGT	03/31/01	FTNNGSS	Storage	Caledonia City Gate		141,994		141,994		
300084	CNG	CNGT	03/31/01	GSS		Injection - Less than 50% - 180 days		31,550	31,550	31,550		
300084	CNG	CNGT	03/31/01	GSS		Injection - More than 50% - 214 days		26,537	26,537	26,537		
300084	CNG	CNGT	03/31/01	GSS		Storage Capacity		5,678,994	5,678,994	5,678,994		
300084	CNG	CNGT	03/31/01	GSS		Withdrawal MDWQ		139,097	139,097	139,097		
400055	CNG	CNGT	03/31/01	GSS II		Injection - Less than 50%		1,094	1,094	697		
400055	CNG	CNGT	03/31/01	GSS II		Injection - More than 50%		921	921	586		
400055	CNG	CNGT	03/31/01	GSS II		Storage Capacity		197,006	197,006	125,392		
400055	CNG	CNGT	03/31/01	GSS II		Withdrawal MDWQ		2,897	2,897	1,844		
820	CNG	Tennessee	11/01/00	FT	Various Meters	CNGT @ Cornwell	0/100	9,754	9,754			
820	CNG	Tennessee	11/01/00	FT	Various Meters	CNGT @ Cornwell	1/100	1,000	1,000			
820	CNG	Tennessee	11/01/00	FT	Various Meters	CNGT @ Cornwell	1/500	13,619	13,619			
820	CNG	Tennessee	11/01/00	FT	Various Meters	CNGT @ Cornwell	1/800	6,452	6,452			
3915	CNG	Tennessee	11/01/00	FT	Various Meters	CNGT @ South Webster	0/100	3,282	3,282			
3915	CNG	Tennessee	11/01/00	FT	Various Meters	CNGT @ South Webster	1/500	9,795	9,795			
3915	CNG	Tennessee	11/01/00	FT	Various Meters	CNGT @ South Webster	1/800	5,677	5,677			
						Total Tennessee		49,479	49,479			
800370 R1	CNG	TETCO	10/31/00	FT	ELA	AAB		18,145	18,145			
800370 R1	CNG	TETCO	10/31/00	FT	ETX	AAB		5,035	5,035			
800370 R1	CNG	TETCO	10/31/00	FT	STX	AAB		8,134	8,134			
800370 R1	CNG	TETCO	10/31/00	FT	WLA	AAB		12,102	12,102			
800370 R1	CNG	TETCO	10/31/00	FT	M1-M2	CNGT @ Oakford		31,162	31,162			
						Total TETCO		31,162	31,162	-		
3943	CNG	Texas Gas	10/31/05	FT	Henry Hub 4,575; NGPL - Lowry 4,227; Mamou 4,228	CNGT @ Lebanon, OH	Zone SL	15,110	15,110	15,110	15,110	
						Total Texas Gas		15,110	15,110	15,110	15,110	-
6506	CNG	Transco	10/31/12	FT	Utos TGPL	CNGT @ Leidy	Zone 3	9,425	9,425	9,425	9,425	9,425
6506	CNG	Transco	10/31/12	FT	Ragley TET	CNGT @ Leidy	Zone 4	208	208	208	208	208
						Total Transco		9,633	9,633	9,633	9,633	9,633
CITY GATE TOTALS (CNG FTNN + FTNNGSS)								277,690	115,196	277,690	-	-

Rochester Gas and Electric Corporation

RGE

CITY GATE TRANSPORTATION AND STORAGE ASSETS (Contracted Volumes Adjusted for Releases/Assignments)

DEKATHERM - VOLUMES STATED AT INTERCONNECTS

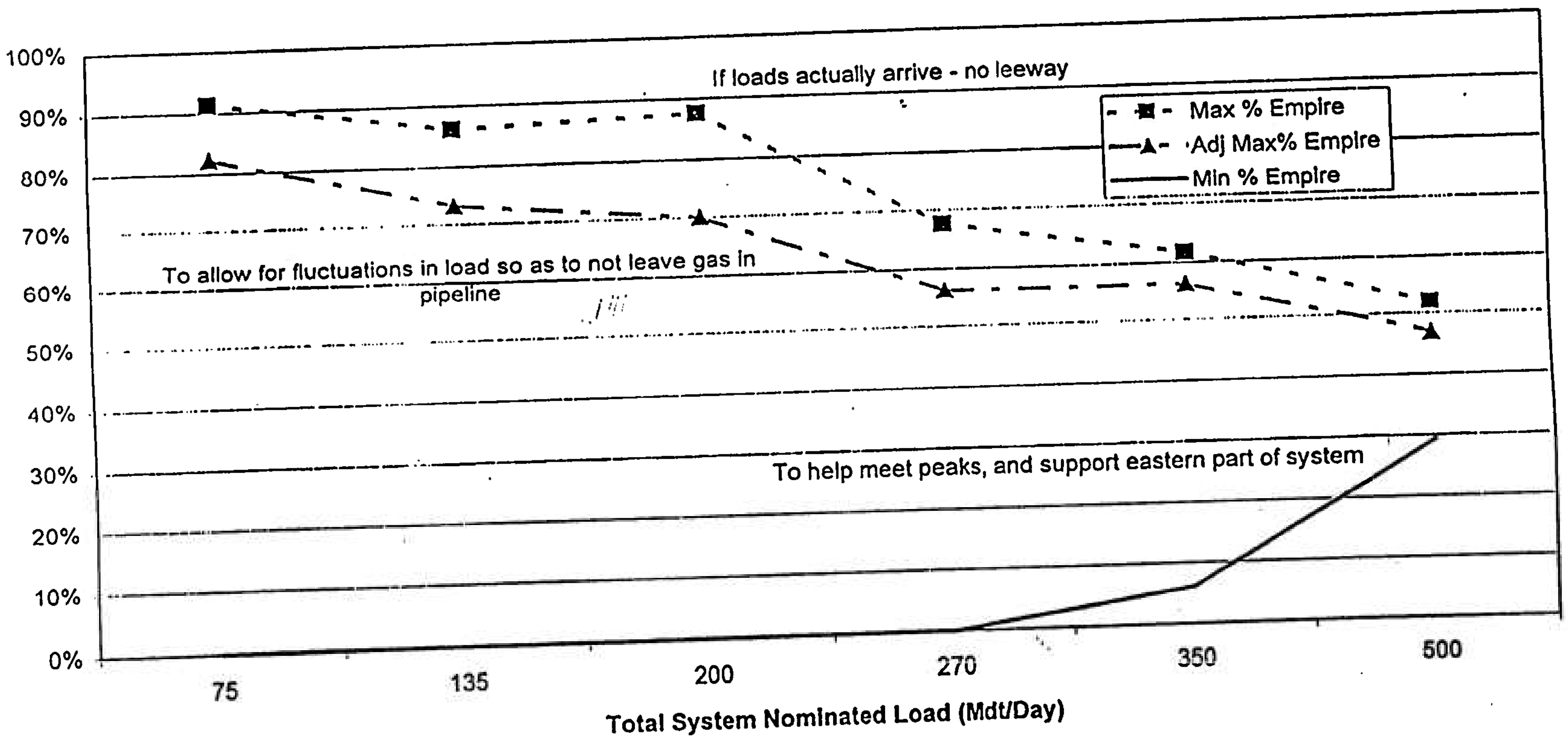
CONTRACT	CITY GATE	PIPELINE	EXP. DATE	RATE SCH.	RECEIPT POINTS	DELIVERY POINTS	ZONE OR LEG	11/1/99 - 3/31/00 MDQ	4/1/00 - 3/31/01 MDQ	4/1/01 - 10/31/08 MDQ
18750	EMPIRE	ANR	10/31/08	FTS-1	Production	Farwell	SE	14,265	22,470	22,470
68750	EMPIRE	ANR	10/31/08	GF-1	Gathering	Gathering	SE	14,265	22,470	22,470
25850	EMPIRE	ANR	10/31/08	FTS-1	Production	Farwell	SW	5,000	34,460	43,000
25900	EMPIRE	ANR	10/31/08	FT-1	Storage	Farwell		111,600	111,600	151,200
33000	EMPIRE	ANR	10/31/08	FSS	Storage Capacity			6,228,915	6,228,915	8,432,435
33000	EMPIRE	ANR Storage	10/31/08	FSS	Injection	Injection		31,110	31,110	42,149
33000	EMPIRE	ANR Storage	10/31/08	FSS	Withdrawal	Withdrawal		113,127	113,127	153,269
FT056	EMPIRE	Great Lakes	10/31/08	FT	Farwell	St. Clair		104,339	A)	A)
FT067	EMPIRE	Great Lakes	10/31/08	FT	Farwell	St. Clair		56,222	B)	B)
						Total Great Lakes		160,561	-	-
SH 2939	EMPIRE	TCPL - SH	10/31/08	FT	St Clair	Chippawa		102,959	102,959	102,959
SH 2937	EMPIRE	TCPL - SH	10/31/08	FT	St Clair	Chippawa		35,674	35,674	35,674
						Total TCPL		138,633	138,633	138,633
95001	EMPIRE	Empire State PL	10/31/08	FT	Chippawa	Mendon City Gate		172,500	172,500	172,500
CITY GATE TOTALS (EMPIRE STATE PL)								172,500	172,500	172,500

A) 104,339 Winter / 0 Summer B) 56,222 Winter / 31,910 Summer

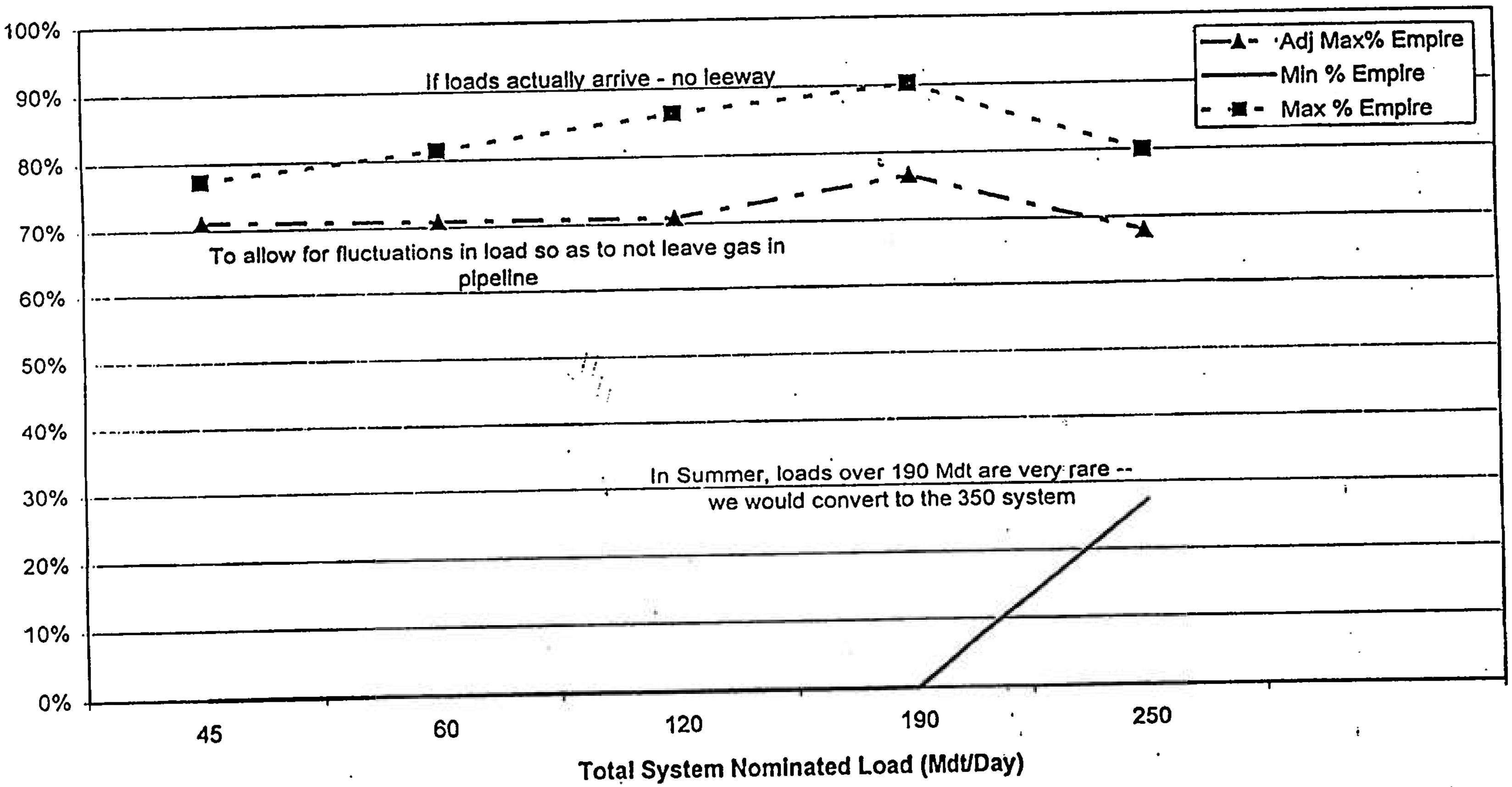
APPENDIX F

EMPIRE CITY GATE - MINIMUM AND MAXIMUM PERCENTAGE OF TOTAL SYSTEM

Empire City Gate - Minimum and Maximum % of Total System
350 psi/250 psi Transmission System Operation
November 1, 1999 - April 30, 2000



Empire City Gate - Minimum and Maximum % of Total System
250 Transmission System Operation
May 1 - Oct 3, 2000



APPENDIX G

CURRENT SUPPLY PORTFOLIO

Current RG&E Gas Suppliers
November 1999

Supplier	Service	DT/day	Expiration Date
Amoco 365 days TETCO	Base Load		10/31/00
Coral 151 days TENN	Base Load		11/1/00
Engage 365 days TETCO	Base Load		10/31/01
Dynegy 151 days TETCO/Texas Gas	Base Load		3/31/00
Dynegy 151 days Southpoint	Swing Load		3/31/00
TransCanada Gas 151 days TCPL	Swing		3./31/00
Aquila 10 days CNGT	Peaking		3/31/00

11/29/99
Current RGE suppliers.doc

APPENDIX J

SUMMARY OF FERC RULEMAKING PROCEEDINGS AND INQUIRIES

SUMMARY OF FERC RULEMAKING PROCEEDINGS AND INQUIRIES.

In Docket Nos. RM98-10 and RM98-12, Regulation of Short-Term Natural Gas Transportation and Regulation of Interstate Natural Gas Transportation Services, respectively, FERC addresses a multitude of issues and presents several proposals concerning both short-term and long-term interstate natural gas transportation service. RG&E has actively monitored these proceedings and has supported comments that were submitted by the American Gas Association ("AGA") on behalf of its member companies. The AGA and RG&E, in general, support positions that, if adopted, would allow RG&E and other LDCs to maximize the value of their existing capacity during the transition to retail competition. At this time, RG&E cannot predict with certainty how FERC will decide these issues. Below is a summary of some of the most critical issues as well as brief discussion of how possible resolution of those issues could impact RG&E. This summary is not intended to be a comprehensive discussion of all the changes to FERC's policy currently under consideration but instead highlights the proposals that are most likely to impact the value of RG&E's interstate capacity.

In Docket Nos. RM98-10 and RM98-12, FERC is considering several changes to its current capacity release regulations. Changes implemented to FERC's capacity release regulations have the potential to significantly affect the value of RG&E's interstate transportation capacity. This is true to the extent that such changes impact the marketability of that capacity on the secondary market. For example, in Docket No. RM98-10, FERC proposes that cost-based regulation be eliminated for short-term transportation and that all short-term capacity, including released capacity, be sold through capacity auctions. This could have the effect of limiting RG&E's ability to enter into prearranged transactions for releasing capacity and creates uncertainty with regard to how such auctions would value RG&E's capacity for short-term transactions.

Additionally, the AGA and other parties have proposed in their comments in Docket Nos. RM98-10 and RM98-12 that the price cap on capacity releases be lifted. The implementation of this proposal could have a limited effect on the valuation of RG&E's capacity. The ability to obtain in excess of maximum rates for RG&E capacity would probably occur only during limited peak periods. To the extent it does occur, this would allow RG&E to offset more of the costs of its capacity under long-term contract. This added flexibility may also increase the value of the capacity on the secondary market because marketers may believe that they would be able to remarket the capacity for greater than maximum rates in the absence of an artificial price cap. Generally, however, RG&E's capacity is valued significantly below maximum rates and, therefore, would not be impacted by removal of the price cap.

FERC also proposes to allow the negotiation of terms and conditions of service as well as the negotiation of rates as is currently permitted. The adoption of this proposal could provide RG&E additional flexibility to the extent it is required to enter into additional contracts for transportation service. This will not directly benefit RG&E with respect to its current long-term contracts. However, it could potentially allow pipelines to negotiate deals that are more attractive to other customers, thereby making the pipeline more willing to negotiate buyouts on terms more favorable to RG&E.

In addition to the proposals discussed above, the AGA made several recommendations in its comments in Docket No. RM98-12 that would positively impact the value of RG&E's capacity. These proposals include the elimination of the "shipper must have title" rule, increasing the flexibility of capacity turnback requirements in the event of facility expansion and several provisions to ensure reasonable recourse rates are available to customers.

APPENDIX K

PARTICIPATION IN FERC PROCEEDINGS

ROCHESTER GAS AND ELECTRIC CORPORATION
MOTIONS TO INTERVENE

PIPELINE	DOCKET NUMBER/ CASE NUMBER	DATE FILED BY RG&E
Texas Gas Transmission Corporation	Docket No. TM87-3-18-000	February 7, 1997
Transcontinental Gas Pipe Line Company	Docket No. CP97-193-000	February 14, 1997
Transcontinental Gas Pipe Line Company	Docket No. CP97-312-000	April 11, 1997
CNG Transmission Corporation	Docket No. RP97-349	May 8, 1997
CNG Transmission Corporation	Docket No. RP97-355-000	May 9, 1997
Texas Eastern Transmission Corporation	Docket No. CP97-644-000	August 21, 1997
Texas Eastern Transmission Corporation	Docket No. CP97-642-000	August 21, 1997
Transcontinental Gas Pipe Line Company	Docket No. TM97-12-29-000	September 8, 1997
Texas Gas Transmission Corporation	Docket No. RP97-492-000	September 8, 1997
Great Lakes Gas Transmission Limited Partnership	Docket No. RP97-475-000	September 8, 1997
CNG Transmission Corporation	Docket No. RP97-499-000	September 10, 1997
Texas Eastern Transmission Corporation	Docket No. RP97-527-000	September 24, 1997
NorAm Gas Transmission Company v. FERC	Case No. 97-1541	September 26, 1997
Equitable Gas Company v. FERC	Case No. 97-1590	September 26, 1997
Consolidated Edison Company of New York, Inc., Long Island Lighting Company, Public Service Electric and Gas Company and the Brooklyn Union Gas Company v. FERC	Case No. 97-1554	October 2, 1997

PIPELINE	DOCKET NUMBER/ CASE NUMBER	DATE FILED BY RG&E
New England Power Company v. FERC	Case No. 97-1560	October 2, 1997
JMC Power Projects v. FERC	Case No. 97-1580	October 2, 1997
ANR Pipeline Company	Docket No. RP97-538-000	October 7, 1997
Niagara Mohawk Power Corporation	Docket No. ER97-4568-000	October 7, 1997
CNG Transmission Corporation	Docket No. RP98-10-000	October 14, 1997
ANR Pipeline Company	Docket No. CP97-765-000	October 20, 1997
Tennessee Gas Pipeline Company	Docket No. RP98-16-000	October 24, 1997
Transcontinental Gas Pipe Line Company	Docket No. TM98-2-29-000	October 29, 1997
Texas Eastern Transmission Corporation	Docket No. RP98-30-000	November 12, 1997
Tennessee Gas Pipeline Company	Docket No. CP98-39-000	November 12, 1997
Tennessee Gas Pipeline Company	Docket No. MG98-4-000	November 25, 1997
Transcontinental Gas Pipe Line Company	Docket No. TM98-4-29-000	December 1, 1997
Transcontinental Gas Pipe Line Company	Docket No. RP98-58-000	December 3, 1997
Tennessee Gas Pipeline Company	Docket No. RP98-56-000	December 3, 1997
ANR Pipeline Company	Docket No. RP98-68-000	December 8, 1997
Transcontinental Gas Pipe Line Corporation	Docket No. RP98-67-000	December 8, 1997
Municipal Defense Group v. FERC	Case No. 97-1673	December 8, 1997
ANR Pipeline Company	Docket No. RP98-81-000	December 15, 1997
Tennessee Gas Pipeline Company	Docket No. RP98-79-000	December 16, 1997

PIPELINE	DOCKET NUMBER/ CASE NUMBER	DATE FILED BY RG&E
ANR Pipeline Company	Docket No. TM97-2-48-001	December 16, 1997
ANR Pipeline Company v. Transcontinental Gas Pipe Line Corporation	Docket No. CP98-74-000	December 17, 1997
Tennessee Gas Pipeline Company	Docket No. RP98-84-000	December 17, 1997
ANR Pipeline Company	Docket No. RP98-92-000	December 29, 1997
Texas Eastern Transmission Corporation	Docket No. RP98-83-000	December 31, 1997
Tennessee Gas Pipeline Company	Docket No. CP98-121-000	December 31, 1997
Great Lakes Gas Transmission Limited Partnership	Docket No. CP98-143-000	January 12, 1998
Texas Gas Transmission Corporation	Docket No. TM98-3-18-000	January 12, 1998
Tennessee Gas Pipeline Company	Docket No. RP98-99-000	January 12, 1998
ANR Pipeline Company	Docket No. RP98-102-000	January 12, 1998
Texas Eastern Transmission Corporation	Docket No. TM98-2-17-000	January 12, 1998
CNG Transmission Corporation	Docket No. RP98-103-000	January 12, 1998
ANR Pipeline Company	Docket No. RP98-107-000	January 12, 1998
CNG Transmission Corporation v. FERC	Case No. 97-1722	January 14, 1998
Tennessee Gas Pipeline Company	Docket No. GT98-13-000	February 11, 1998
Great Lakes Gas Transmission Limited Partnership	Docket No. RP98-96-000	February 11, 1998
Millennium Pipeline Company L.P.*	Docket No. RP98-150, 154, 155 and 156-000	February 24, 1998
Texas Eastern Transmission Corporation	Docket No. CP98-211-000	February 24, 1998

PIPELINE	DOCKET NUMBER/ CASE NUMBER	DATE FILED BY RG&E
Tennessee Gas Pipeline Company	Docket No. RP98-135-000	February 25, 1998
Texas Eastern Transmission Corporation	Docket No. RP98-137-000	March 2, 1998
Tennessee Gas Pipeline Company	Docket No. RP98-136-000	March 2, 1998
Tennessee Gas Pipeline Company	Docket Nos. RP96-312-009 and GT98-19-000	March 3, 1998
Tennessee Gas Pipeline Company	Docket No. RP98-140-000	March 4, 1998
Tennessee Gas Pipeline Company	Docket No. CP98-220-000	March 4, 1998
Texas Eastern Transmission Corporation	Docket No. CP98-212-000	March 4, 1998
The Brooklyn Union Gas Company, Consolidated Edison Company of New York, Inc., PECO Energy Company v. FERC	Case No. 98-60057	March 6, 1998
Texas Eastern Transmission Corporation	Docket No. RP98-142-000	March 11, 1998
CNG Transmission Corporation	Docket No. TM98-3-22-000	March 11, 1998
ANR Pipeline Company	Docket No. TM98-2-48-000	March 11, 1998
ANR Pipeline Company	Docket No. RP98-143-000	March 11, 1998
ANR Pipeline Company	Docket No. RP98-144-000	March 11, 1998
Transcontinental Gas Pipe Line Corporation	Docket No. TM98-9-29-000	March 11, 1998
Transcontinental Gas Pipe Line Corporation	Docket No. RP98-150-000	March 11, 1998
Great Lakes Gas Transmission Limited Partnership*	Docket No. RP98-156-000	March 16, 1998
CNG Transmission Corporation v. FERC	Case No. 98-1091	March 18, 1998

PIPELINE	DOCKET NUMBER/ CASE NUMBER	DATE FILED BY RG&E
Texas Eastern Transmission Corporation	Docket No. CP98-239-000	March 19, 1998
Process Gas Consumers Group v. FERC	Case No. 98-1075	March 19, 1998
Bay State Gas Company, et al. v. FERC	Case No. 98-1089	March 19, 1998
ANR Pipeline Company	Docket No. RP98-42-002	April 1, 1998
ANR Pipeline Company	Docket No. RP98-177-000	April 9, 1998
ANR Pipeline Company	Docket No. RP98-176-000	April 9, 1998
ANR Pipeline Company	Docket No. RP98-175-000	April 9, 1998
People of the State of New York and the Public Service Commission of the State of New York v. FERC	Case No. 98-1100	April 10, 1998
Cities of Clarksville, Springfield, and Portland, Tennessee, the Northwest Alabama Gas District, the West Tennessee Public Utility District, the Humphreys County Utility District, and the Greater Dickson Gas Authority, Tennessee	Case No. 98-1099	April 10, 1998
CNG Transmission Corporation	Docket No. RP98-171-000	April 13, 1998
Texas Gas Transmission Corporation	Docket No. RP98-170-000	April 13, 1998
ANR Pipeline Company*	Docket No. RP98-178-000	April 13, 1998
ANR Pipeline Company*	Docket No. RP98-168-000	April 13, 1998
Great Lakes Gas Transmission Limited Partnership*	Docket No. CP98-309-000	April 24, 1998
ANR Pipeline Company	Docket No. RP98-212-000	May 13, 1998
Tennessee Gas Pipeline Company	Docket No. RP98-188-000	May 14, 1998

PIPELINE	DOCKET NUMBER/ CASE NUMBER	DATE FILED BY RG&E
Texas Eastern Transmission Corporation	Docket No. CP98-399-000	May 27, 1998
Enron Energy Services Inc. and Enron Capital & Trade Resources Corp.*	Docket No. RP98-220-000	May 28, 1998
ANR Pipeline Company	Docket No. RP98-228-000	June 9, 1998
ANR Pipeline Company	Docket No. RP98-230-000	June 9, 1998
CNG Transmission Corporation	Docket No. RP98-234-000	June 9, 1998
Texas Gas Transmission Corporation	Docket No. TM98-4-18-000	June 9, 1998
Transcontinental Gas Pipe Line Corporation	Docket No. CP98-540-000	June 11, 1998
Tennessee Gas Pipeline Company	Docket No. RP98-737-000	June 15, 1998
Tennessee Gas Pipeline Company	Docket No. RP98-332-000	July 13, 1998
Transcontinental Gas Pipe Line Corporation	Docket No. RP98-317-000	July 13, 1998
Transcontinental Gas Pipe Line Corporation	Docket No. RP98-284-000	July 13, 1998
CNG Transmission Corporation	Docket No. RP98-278-000	July 13, 1998
Village of Lakewood, New York	Docket No. SC98-2-000	August 4, 1998
ANR Pipeline Company v. FERC	Case No. 98-1325	August 10, 1998
Texas Gas Transmission Corporation	Docket No. TM99-1-18-000	September 9, 1998
ANR Pipeline Company	Docket No. RP98-377-000	September 14, 1998
Transcontinental Gas Pipe Line Corporation	Docket No. RP98-381-000	September 14, 1998
Tennessee Gas Pipeline Company	Docket No. RP98-378-000	September 14, 1998
Great Lakes Gas Transmission Limited Partnership	Docket No. CP98-767-000	October 6, 1998

PIPELINE	DOCKET NUMBER/ CASE NUMBER	DATE FILED BY RG&E
CNG Transmission Corporation	Docket No. RP98-429-00	October 13, 1998
ANR Pipeline Company	Docket No. RP99-188	November 12, 1998
Great Lakes Gas Transmission Limited Partnership	Docket Nos. TM99-1-55 & RP99-129	November 12, 1998
Tennessee Gas Pipeline Company	Docket No. RP99-113	November 12, 1998
Tennessee Gas Pipeline Company	Docket No. GT99-4	November 16, 1998
Texas Eastern Transmission Corporation	Docket No. CP99-18	November 16, 1998
Texas Eastern Transmission Corporation	Docket No. RP99-135	November 16, 1998
ANR Pipeline Company	Docket No. RP99-142	November 17, 1998
CNG Transmission Corporation	Docket NO. TM99-2-22	December 2, 1998
CNG Transmission Corporation	Docket No. RP99-156	December 2, 1998
Transcontinental Gas Pipe Line Corporation	Docket No. RP99-170	December 14, 1998
ANR Pipeline Company	Docket No. RP99-160	December 14, 1998
Tennessee Gas Pipeline Company	Docket No. RP99-167	December 14, 1998
TriState Pipeline, L.L.C.	Docket Nos. CP99-61, 62, 63 and 64-000	January 5, 1999
Texas Gas Transmission Corporation	Docket Nos. TM99-3-18	January 11, 1999
ANR Pipeline Company	Docket No. RP99-197	January 12, 1999
Texas Eastern Transmission Corporation	Docket No. TM99-2-17	January 12, 1999

PIPELINE	DOCKET NUMBER/ CASE NUMBER	DATE FILED BY RG&E
NE Hub Partners v. CNG Transmission Corp.	Docket No. CP99-106-000	January 15, 1999
ANR Pipeline Company	Docket No. CP99-151-000	February 9, 1999
Great Lakes Gas Transmission Limited Partnership*	Docket No. RP99-220-000	February 17, 1999
Consumer Services Associate, Inc. d/b/a United Gas Services	Docket No. RP99-221-000	February 25, 1999
Transcontinental Gas Pipeline Corporation	Docket No. CP99-192-000	March 3, 1999
CNG Transmission Corporation	Docket No. CP99-96-001	March 4, 1999
ANR Pipeline Company	Docket No. RP99-235-000	March 10, 1999
ANR Pipeline Company	Docket No. RP99-236-000	March 10, 1999
Transcontinental Gas Pipe Line Corporation	Docket No. TM99-6-29	March 15, 1999
Transcontinental Gas Pipe Line Corporation	Docket No. RP99-250-000	March 15, 1999
CNG Transmission Corporation	Docket No. TM99-3-22-000	March 15, 1999
ANR Pipeline Company*	Docket No. RP99-255-000	March 15, 1999
ANR Pipeline Company	Docket No. RP99-256-000	March 15, 1999
Texas Eastern Transmission Corporation	Docket No. RP99-243-000	March 15, 1999
ANR Pipeline Company	Docket No. TM99-2-48-000	March 15, 1999
ANR Pipeline Company	Docket No. CP99-241-000	April 9, 1999
Transcontinental Gas Pipe Line Corporation	Docket No. RP99-278-000	April 23, 1999
Transcontinental Gas Pipe Line Corporation	Docket No. TM99-7-29-000	April 23, 1999

PIPELINE	DOCKET NUMBER/ CASE NUMBER	DATE FILED BY RG&E
Tennessee Gas Pipeline Company	Docket No. CP99-262-000	April 23, 1999
ANR Pipeline Company	Docket No. RP99-301-000	May 12, 1999
Texas Eastern Transmission Corporation	Docket No. RP99-294-000	May 12, 1999
ANR Pipeline Company	Docket No. RP99-298-000	May 12, 1999
Transcontinental Gas Pipe Line Corporation	Docket No. RP99-291-000	May 12, 1999
Tennessee Gas Pipeline Company	Docket No. GT99-26-000	May 12, 1999
Transcontinental Gas Pipe Line Corporation	Docket No. CP99-392-000	May 12, 1999
ANR Pipeline Company	Docket No. RP99-319-000	June 9, 1999
ANR Pipeline Company	Docket No. RP99-320-000	June 9, 1999
CNG Transmission Corporation	Docket No. RP99-321-000	June 9, 1999
Tennessee Gas Pipeline Company	Docket No. RP99-326-000	June 14, 1999
Tennessee Gas Pipeline Company	Docket No. RP99-328-000	June 14, 1999
Tennessee Gas Pipeline Company	Docket No. RP99-325-000	June 14, 1999
Texas Gas Transmission Corporation	Docket No. RP99-327-000	June 14, 1999
ANR Pipeline Company	Docket No. RP99-357-000	July 12, 1999
Great Lakes Gas Transmission Limited Partnership*	Docket No. RP99-360-000	July 12, 1999
Texas Gas Transmission Corporation	Docket No. TM99-2-17-000	July 21, 1999
Texas Gas Transmission Corporation	Docket No. RP99-418-000	July 21, 1999
Transcontinental Gas Pipeline Corporation	Docket No. RP99-380-000	July 21, 1999

PIPELINE	DOCKET NUMBER/ CASE NUMBER	DATE FILED BY RG&E
Tennessee Gas Pipeline Company	Docket No. RP99-412-000	July 21, 1999
Dominion Resource, Inc. and Consolidated Natural Gas Company	Docket No. EC99-81-000	August 6, 1999
Transcontinental Gas Pipe Line Corporation	Docket No. RM99-8-29-000	August 9, 1999
CNG Transmission Corporation	Docket No. RP99-446-000	August 9, 1999
CNG Transmission Corporation	Docket No. RP99-457-000	August 13, 1999
Great Lakes Gas Transmission Limited Partnership	Docket No. RP99-466-000	August 23, 1999
Texas Gas Transmission Corporation	Docket No. RP99-475-000	September 1, 1999
North American Energy Conservation, Inc. v. CNG Transmission Corporation	Docket No. RP99-477-000	September 3, 1999
Texas Eastern Transmission Corporation	Docket No. RP99-480-000	September 7, 1999
ANR Pipeline Company	Docket No. RP99-498-000	September 14, 1999
CNG Transmission Corporation	Docket No. RP99-519-000	October 12, 1999
Texas Eastern Transmission Corporation	Docket No. RP00-7-000	October 12, 1999
CNG Transmission Corporation	Docket No. RP99-520-000	October 12, 1999
CNG Transmission Corporation*	Docket No. RP00-15-000	October 14, 1999
ANR Pipeline Company	Docket No. RP00-30-000	November 2, 1999
Texas Eastern Transmission Corporation	Docket No. RP00-34-000	November 8, 1999
ANR Pipeline Company	Docket No. RP00-44-000	November 10, 1999
ANR Pipeline Company	Docket No. RP00-45-000	November 10, 1999

PIPELINE	DOCKET NUMBER/ CASE NUMBER	DATE FILED BY RG&E
Texas Eastern Transmission Corporation	Docket No. RP00-50-000	November 10, 1999
Great Lakes Gas Transmission Limited Partnership	Docket No. RP00-63-000	November 24, 1999
Transcontinental Gas Pipe Line Corporation	Docket No. RP00-64-000	November 24, 1999
Transcontinental Gas Pipe Line Corporation	Docket No. RP00-65-000	November 24, 1999
Tennessee Pipeline Company	Docket No. RP00-66-000	November 24, 1999
CNG Transmission Corporation*	Docket No. RP00-74-000	November 30, 1999
Texas Gas Transmission Corporation	Docket No. RP00-80-000	December 13, 1999
Texas Gas Transmission Corporation*	Docket No. RP00-83-000	December 13, 1999
Great Lakes Gas Transmission Corporation	Docket No. RP00-85-000	December 13, 1999
ANR Pipeline Company	Docket No. RP99-88-000	December 13, 1999
ANR Pipeline Company	Docket No. RP99-89-000	December 13, 1999
Tennessee Pipeline Company	Docket No. RP00-93-000	December 13, 1999
Tennessee Pipeline Company	Docket No. RP00-100-000	December 13, 1999
Transcontinental Gas Pipe Line Corporation	Docket No. RP00-129-000	December 13, 1999
AmerGen Energy Company, L.L.C.	Docket No. EG00-27-000	December 14, 1999

* Protest or Comments also filed.

APPENDIX L

MIGRATION FORECAST

ROCHESTER GAS AND ELECTRIC CORPORATION

CAPACITY COST MITIGATION FILING

LOAD FORECAST

		Nov 1, 1999	Nov 1, 2000	Nov 1, 2001	Nov 1, 2002
Month	Retail (no migration)	13% migration	23% migration	35% migration	50% migration
Annual Total	36,746,445	32,143,408	28,448,763	24,015,190	18,473,223
Winter	27,171,046	23,725,810	20,998,706	17,726,180	13,635,523
Summer	9,575,399	8,417,597	7,450,057	6,289,010	4,837,700

APPENDIX N

OPEN SEASON SOLICITATION PACKAGE

December 21, 1999

Re: Open Season for the Long-term or Permanent Release of Firm Transportation and Storage Capacities

The Energy Supply Management Group of the Rochester Gas and Electric Corporation is in the process of restructuring its upstream portfolio of pipeline and storage assets and invites you to submit an Open Season Bid Form for a long - term or permanent release of the available capacities. An Open Season Bid Form and a listing of the available capacities are attached. The Bid Form submittal due date is 5pm (Eastern Standard Time) January 21, 2000. All bids shall detail the term of the proposed release, pricing, the quantity of firm pipeline capacity and/or storage capacity desired, receipt and delivery points, and any other terms and conditions specific to the bid.

Rochester Gas and Electric will evaluate each bid to determine the best value considering the duration of the proposed release, the proposed reservation price and impact of RG&E's supply portfolio. Preference will be given to long term releases as well as releases that link pipelines, however, all bids will be considered.

It is our intention that capacity be released effective April 1, 2000.

The Bid Form should be faxed to 716/771-2825:

Rochester Gas and Electric Corporation
89 East Avenue
Rochester, New York 14649-0001
Attention: Gregory J. Fuller
Manager, Gas Supply & Contract Management

This open season bid request is subject to the terms of this letter and the enclosed (1) supplemental terms and conditions, and (2) open season bid request package.

If you have any questions, **please contact Robert Lauterbach at 716/724-8753.**

Sincerely,

Gregory Fuller
Manager, Gas Supply & Contract Management
Energy Supply Management

Enclosures

Rochester Gas and Electric Corporation
Open Season for the Long-term or Permanent Release of Firm Transportation and Storage Capacities

Supplemental Terms and Condition Sheet

A. CONFIDENTIALITY

RG&E and its representatives shall take reasonable efforts to protect information that is clearly identified as confidential from disclosure to third parties.

The Company shall request, in connection with any submission to the PSC or other authority having jurisdiction or oversight responsibilities for the Company's procurement activities, that information designated as confidential by the respondent be treated as confidential and proprietary in accordance with applicable regulations.

B. ACCEPTENCE/REJECTION OF BIDS

The Company reserve the right to accept or reject any and/or all bids, enter into negotiations with selected respondents, and to award the contract to bidders other than the high bidder and in such a manner as will in its sole opinion best meet the objectives described in this Open Season. The Company shall reserve the right to verify the credit worthiness of any respondent prior to acceptance of any bid consistent with pipeline industry standards. The Company may elect to delay all or part of the award schedule and to request rebids if necessary.

C. BINDING BIDS

All bids should be binding on the bidder for not less than 30 days.

D. ALL ACCEPTED BIDS WILL BE POSTED

All accepted bids will be posted on the affected pipeline's EBB if required, and are subject to the respective pipeline's FERC gas tariff as applicable.

E. BIDDERS WANTING SEVERAL PIPELINES

Bidders wishing to bid on a path that uses several pipelines' capacity should clearly state whether or not bids are contingent on the award of the total path.

F. NOTES ON ANR/EMPIRE

ANR/Empire contracts are negotiated rates, which apply to primary points. Any additional payments required due to assignee's use of secondary points will be the responsibility of the assignee.

G. EMPIRE STATE PIPELINE

Empire State Pipeline is an intrastate pipeline subject to NYPSC jurisdiction. Please refer to their new web site (www.empirepipeline.com) for their rates and pipeline information. Any Empire assignment requires a contract assignment.

OPEN SEASON BID REQUEST ON PIPELINE AND STORAGE ASSETS

BY

ROCHESTER GAS AND ELECTRIC CORPORATION

Enclosures:

Appendix A	**Listing of Assets (Pages 4 – 7)**
Appendix B	**Diagram of Assets (Pages 8 – 10)**
Appendix C	**List of Pipeline Web Sites (Page 11)**
Appendix D	**Bid Forms (Pages 12 - 14)**

APPENDIX A

THE COMPANY'S CURRENT TRANSPORTATION

AND STORAGE COMMITMENTS

CNGT – City Gate Assets

Rochester Gas and Electric Corporation

CITY GATE TRANSPORTATION AND STORAGE ASSETS (Contracted Volumes Adjusted for Releases/Assignments)

DEKATHERM - VOLUMES STATED AT CNGT INTERCONNECTS

CONTRACT	PIPELINE	ZONE OR LEG	EXP. DATE	RATE SCH.	RECEIPT POINTS	DELIVERY POINTS	4/1/00 - 10/31/00 MDQ	11/1/00 - 3/31/01 MDQ	4/1/01 - 10/31/05 MDQ	11/1/05 - 10/31/12 MDQ
100021	CNGT		03/31/01	FTNN	Cornwell	Caledonia City Gate	30,025	30,025		
100021	CNGT		03/31/01	FTNN	South Webster	Caledonia City Gate	18,326	18,326		
100021	CNGT		03/31/01	FTNN	Oakford	Caledonia City Gate	42,666	42,666		
100021	CNGT		03/31/01	FTNN	Lebanon	Caledonia City Gate	14,766	14,766		
100021	CNGT		03/31/01	FTNN	Leidy - Transco	Caledonia City Gate	9,413	9,413		
200103	CNGT		03/31/01	FT	Leidy - Tetco	Caledonia City Gate		20,500		
						Total CNG FT/FTNN	**115,196**	**135,696**		
700018	CNGT		03/31/01	FTNNGSS	Storage	Caledonia City Gate		141,994		
300084	CNGT		03/31/01	GSS		Injection - Less than 50% - 180 days	31,550	31,550		
300084	CNGT		03/31/01	GSS		Injection - More than 50% - 214 days	26,537	26,537		
300084	CNGT		03/31/01	GSS		Storage Capacity	5,678,994	5,678,994		
300084	CNGT		03/31/01	GSS		Withdrawal MDWQ	139,097	139,097		
400055	CNGT		03/31/01	GSS II		Injection - Less than 50%	1,094	697		
400055	CNGT		03/31/01	GSS II		Injection - More than 50%	921	586		
400055	CNGT		03/31/01	GSS II		Storage Capacity	197,006	125,392		
400055	CNGT		3/31/01	GSS II		Withdrawal MDWQ	2,897	1,844		
820	Tennessee	0/100	11/01/00	FT	See Attached List	CNGT @ Cornwell	9,754			
820	Tennessee	1/100	11/01/00	FT	See Attached List	CNGT @ Cornwell	1,000			
820	Tennessee	1/500	11/01/00	FT	See Attached List	CNGT @ Cornwell	13,519			
820	Tennessee	1/800	11/01/00	FT	See Attached List	CNGT @ Cornwell	6,452			
3915	Tennessee	0/100	11/01/00	FT	See Attached List	CNGT @ South Webster	3,282			
3915	Tennessee	1/500	11/01/00	FT	See Attached List	CNGT @ South Webster	9,795			
3915	Tennessee	1/800	11/01/00	FT	See Attached List	CNGT @ South Webster	5,677			
						Total Tennessee	49,479			
800370 R1	TETCO		10/31/00	FT	ELA	M1 - 30 24,828				
800370 R1	TETCO		10/31/00	FT	ETX	M1 - 24 3,518; M1 - TXG 1,252				
800370 R1	TETCO		10/31/00	FT	STX	M1 - TGC 828				
800370 R1	TETCO		10/31/00	FT	WLA	M1 - TXG 382; M1 - TGC 828				
800370 R1	TETCO		10/31/00	FT	M1-M2	CNGT @ Oakford	31,162			
						Total TETCO	31,162			
3943	Texas Gas	Zone SL	10/31/05	FT	Henry Hub 4,575; NGPL - Lowry 4,227; Mamou 4,228	CNGT @ Lebanon, OH	15,110	15,110	15,110	
						Total Texas Gas	15,110	15,110	15,110	
6506	Transco	Zone 3	10/31/12	FT	Utos TGPL	CNGT @ Leidy		9,425	9,425	9,425
6506	Transco	Zone 4	10/31/12	FT	Ragley TET	CNGT @ Leidy		208	208	208
						Total Transco		9,633	9633	9633
CITY GATE TOTALS (CNG FTNN + FTNNGSS)							115,196	277,690		

Empire – City Gate Assets

Rochester Gas and Electric Corporation									RG&E
CITY GATE TRANSPORTATION AND STORAGE ASSETS (Contracted Volumes Adjusted for Releases/Assignments)									
DEKATHERM - VOLUMES STATED AT INTERCONNECTS									
CONTRACT	PIPELINE	ZONE OR LEG	EXP. DATE	RATE SCH.	RECEIPT POINTS	DELIVERY POINTS	11/1/99 - 10/31/00 MDQ	11/1/00 - 3/31/01 MDQ	4/1/01 - 10/31/08 MDQ
18750	ANR	SE	10/31/08	FTS-1	SE Headstation	ANRPL Storage or Farwell	14,265	14,265	22,470
68750	ANR	SE	10/31/08	GF-1	SE Gathering Headstation	SE Gathering Headstation	14,265	14,265	22,470
25850	ANR	SW	10/31/08	FTS-1	SW Headstation	ANRPL Storage or Farwell	5,000	34,460	43,000
25900	ANR		10/31/08	FT-1	ANRPL Storage	Farwell (Muttonville and Capac)	111,600	111,600	151,200
33000	ANR Storage		10/31/08	FSS	Storage Capacity		6,228,915	6,228,915	8,432,435
33000	ANR Storage		10/31/08	FSS	Injection		31,110	31,110	42,149
33000	ANR Storage		10/31/08	FSS	Withdrawal		113,127	113,127	153,269
FT056	Great Lakes		10/31/08	FT	Farwell (Muttonville and Capac)	St. Clair	A)	A)	A)
FT067	Great Lakes		10/31/08	FT	Farwell (Muttonville and Capac)	St. Clair	B)	B)	B)
						Total Great Lakes	C)	C)	C)
SH 2939	TCPL - SH		10/31/08	FT	St Clair (2nd Parkway&Dawn)	Chippawa	102,959	102,959	102,959
SH 2937	TCPL - SH		10/31/08	FT	St Clair (2nd Parkway&Dawn)	Chippawa	35,674	35,674	35,674
						Total TCPL	138,633	138,633	138,633
95001	Empire State PL		10/31/08	FT	Chippawa	Mendon City Gate	172,500	172,500	172,500
CITY GATE TOTALS (EMPIRE STATE PL)							172,500	172,500	172,500
		A) 104,339 Winter / 0 Summer B) 56,222 Winter / 31,910 Summer C) 160,561 Winter / 31,910 Summer							
ANR Storage is an annual Unratchedted contract and injections and withdrawals can be made any day.									
If storage balance on April 1 >20% capacity, then the incremental amount will be reduced by the injection fuel rate (1.05%).									

Storage Notes:

ANR: -- Annual Storage Contract with no ratchets, daily injection and withdrawal any day of the year. For balances held in storage on April 1, greater than 20% of the MASQ, ANR will levy a 1.05 % fuel charge. Injections based on 214 days and withdrawals based on 55 days.

CNGT: -- Ratchet no-notice storage service. GSS transport reduces from 139,097dt to 128,000 dt at 35% full, 97,000 dt at 16% full and 87,000 dt at 10% full. GSSII transport reduced from 2,897 dt to 2,700 dt at 25% full, 2,000 dt at 16% full, 1,800 dt at 10% full.

Summer injections based on 180 days less than 50% full, 214 days over 50% full. Winter injections are limited to 1/214 of the storage quantity.

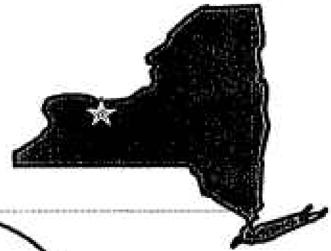
Minimum turnover equals November 1st balance – (25% of MASQ). Amount less than the minimum turnover will cost 2 times the fuel percentage.

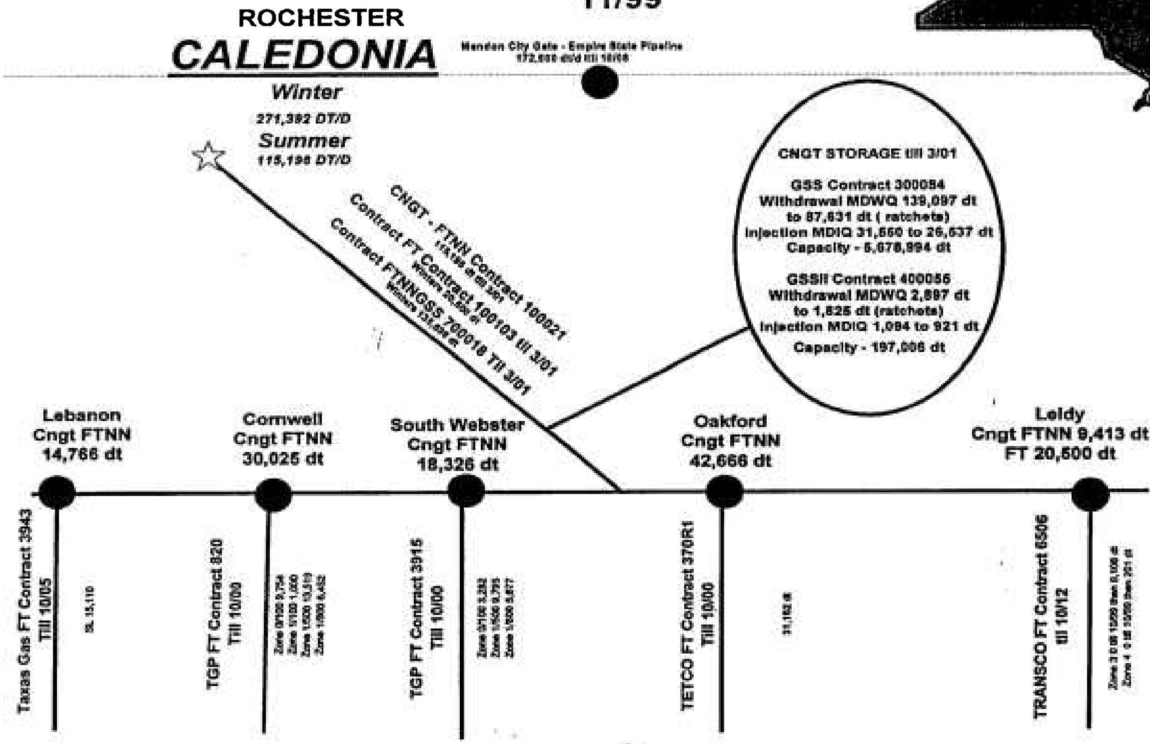
APPENDIX B

DIAGRAM OF THE COMPANY'S PIPELINE

AND STORAGE COMMITMENTS

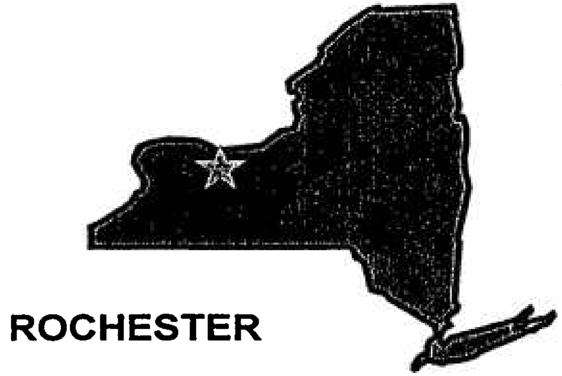
Caledonia City Gate Transportation & Storage Commitments 11/99

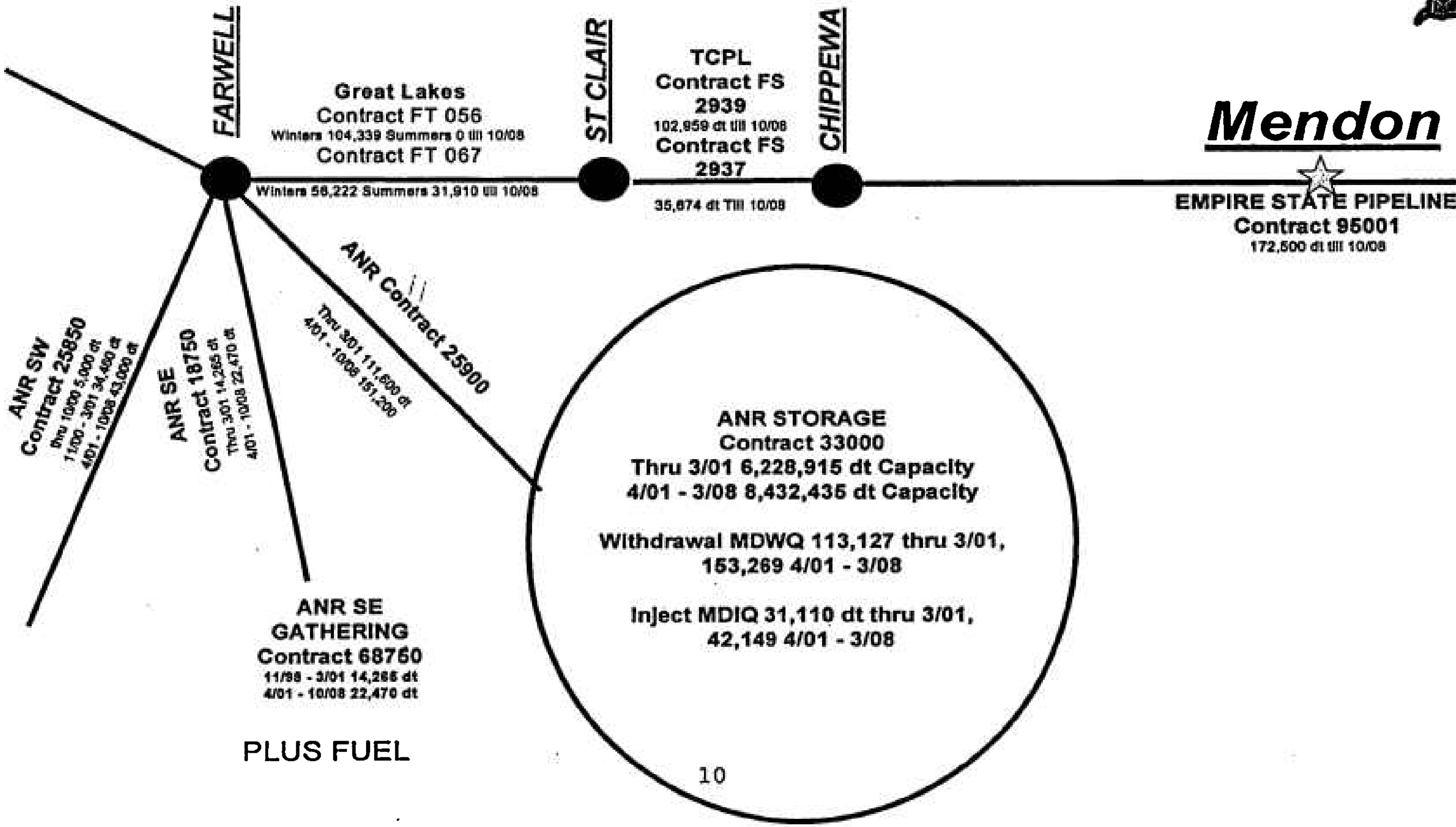




PLUS FUEL

Mendon City Gate Transportation & Storage Commitments 11/99





APPENDIX C

WEB SITES

ANR	http://www.anrpl.com/
CNGT	http://www.cng.com/cngt/
Empire State	http://www.empirepipeline.com/
Great Lakes Transmission	http://www.greatlakesgas.com/
TCPL	http://www.transcanada.com/business/PDFTariff/index.html
Tennessee	http://www.epenergy.com/tgp/
TETCO	http://infopost.link.duke-energy.com/scripts/ndisapi.dll/TE/Home_Frame_TE
Texas Gas	http://www.gasquest.twc.com/
Transco	http://www.tgpl.twc.com/

APPENDIX D

BID FORMS

Rochester Gas and Electric Corporation

Transportation Capacity Open Season Bid Form

Bids are to be faxed to Gregory Fuller 716/771- 2825 and are due by 5:00 P. M. Eastern Time on January 21, 2000.

Rochester Gas and Electric reserves the right to reject any and all bids at its sole discretion.

Customer Information

Name of Contact Person: ______________________ D&B Number ____________

Title: ______________________

Telephone: ______________________

Fax: ______________________

Company Name: ______________________

Company Address: ______________________

Also please mail one copy of your most recent financial statement or annual report.

Quantities/Price/Terms and Conditions

Pipeline	K #	Rate Schedule	Dt/Day	Receipt Point	Delivery Point	Start Date	End Date	Demand $/DT/Day/ MO

Comments: ______________________

Rochester Gas and Electric Corporation

Storage Capacity Open Season Bid Form

Bids are to be faxed to Gregory Fuller 716/771- 2825 and are due by 5:00 P. M. Eastern Time on January 21, 2000.

Rochester Gas and Electric reserves the right to reject any and all bids at its sole discretion.

Customer Information

Name of Contact Person: ______________________ D&B Number ____________

Title: ______________________

Telephone: ______________________

Fax : ______________________

Company Name: ______________________

Company Address: ______________________

Also please mail one copy of your most recent financial statement or annual report.

Quantities/Price/Terms and Conditions

	K #	Capacity MSQ **	MDWQ *	Start Date	End Date	Demand $/DT/Day /Mo.	Capacity $/DT/Day /Mo.	Injection $/DT/Day /Mo.
CNGT – GSS								
ANR – FSS								

Notes: * ANR MDWQ based on 55-days service, CNG based on 40-days service (before ratchets)
**ANR capacity 55 times MDWQ, CNGT capacity 40 times MDWQ.

Comments: ______________________

APPENDIX O

REQUEST FOR PROPOSALS

January 5, 2000

«Title» «FirstName» «LastName»
«Company»
«AddressInside»
«AddressStreet»
«City», «State» «Zip»

Subject: Request for Proposals #6008 for
The Purchase of Natural Gas and Related Assignment of Upstream Capacity

Dear «FirstName»,

We are pleased to enclose our request for proposals for services encompassing the sale of natural gas to the Rochester Gas and Electric (RG&E) at its city-gate. RG&E will assign to one or more suppliers a pro rata portion of RG&E's upstream capacity for the term of the sale. You'll find that the RFP and the supporting enclosures are quite comprehensive.

Please highlight in your response all concepts and actions that will be responsive to the following three key RG&E objectives:

1. Achieve substantial permanent reductions in the Company's city gate unit cost while maintaining reliable service for our customers. Managing price volatility to our customers is also an important factor.

2. Identify strategies and opportunities which optimize the utilization of RG&E assets during the transition through deregulation.

3. Establish a mutually beneficial business relationship that over time will have strategic value for each partner. Such a relationship should be flexible enough to adapt to changing regulatory and market conditions, facilitate efficient information flow between our organizations, and be open to a mutual learning environment to benefit our human resources.

In evaluating proposals, we will particularly consider:

- your capability to manage all upstream commitments (supply, transportation, and storage) in a reliable and cost-effective manner;
- your capability to capture for RG&E the maximum value of our upstream assets, particularly given the new Canadian and U.S. projects intending to add transportation capacity and new supplies which will flow north to south and west to east;
- your responsiveness to this RFP as well as your ability to address the objectives set forth above in a flexible manner.

We look forward to receiving your proposal, six written copies of which must be received by no later than February 3, 2000 at 5 PM.

Proposals should be addressed to (use the enclosed label):

Ms. Judy Blake
Strategic Supply Management
89 East Avenue
Rochester, New York 14649
Phone (716) 771-4085

We expect that by February 25, 2000, we will have completed our preliminary analysis. Following completion, RG&E will individually notify each respondent in writing whether or not its proposal was chosen for further consideration. We expect that by February 28, 2000, we will notify respondents (a short list) with whom we will have follow-up discussions to:

1. ensure mutual understanding of the respondent's proposal
2. make a final selection of respondents with whom we will enter negotiations to reach a definitive contractual agreement.

If you have any questions regarding this request for proposal, please call Robert Lauterbach PHONE (716) 724-8753 - FAX (716) 771-2825.

We look forward to hearing from you.

Sincerely,

Clifton B. Olson
Vice President of Energy Supply

REQUEST FOR PROPOSALS (RFP 6008)

FOR

THE PURCHASE OF NATURAL GAS

AND RELATED ASSIGNMENT OF UPSTREAM CAPACITY

BY

ROCHESTER GAS AND ELECTRIC CORPORATION

JANUARY 5, 2000

REQUEST FOR PROPOSALS FOR THE PURCHASE OF NATURAL GAS

Rochester Gas and Electric Corporation (RG&E or Company) requests proposals for the sale of natural gas to the Company at its city-gate. RG&E will assign to one or more suppliers a pro rata portion of RG&E's upstream capacity for the term of the sale. The term of the sales contract shall be one or more years, commencing May 1, 2000. As upstream capacity contracts expire, RG&E does not anticipate renewing them. Suppliers are encouraged to modify the assigned contracts to better conform to their own needs and to make them more market sensitive.

The Company is a regulated electric and natural gas distribution utility operating in New York. The Company serves 280,000 gas customers, predominantly composed of residential accounts, substantial portions of which are heating accounts. The Company's current estimated retail peak day is 365,000[1] dt/day and retail annual send-out (normalized) is 32 BCF. Although RG&E is an integrated distribution system, there are some capacity constraints on the distribution system which affect where gas can be delivered. These are more fully discussed below. The Company has an obligation to provide reliable and least-cost supply and transportation service to its sales customers. The Company maintains portfolios of gas supply, interstate transportation, and underground storage rights, in order to provide such service in a least-cost and reliable manner. A description of the Company's upstream transportation, storage and purchase contracts, along with load duration curves, indicating the Company's forecast of city gate requirements for its retail sales customers is

[1] Based on its current tariff, RG&E retains the obligation to meet a portion of the transportation load under peak day conditions.

contained in the attached appendices.

A. <u>DESCRIPTION OF THE PORTFOLIO</u>

The Company has transportation capacity and underground storage entitlements on multiple upstream pipelines that provide access to production fields and provide operational flexibility and the ability to move gas supplies along various transportation paths. Ultimately, all upstream supplies are delivered to the Company's city gates via CNG Transmission Corporation ("CNGT") or Empire State Pipeline ("Empire"). Refer to Appendices A & B for further description of the assets.

About five percent of the load is required in our Pavilion district and is served through five interconnects off CNGT. The remainder of the load is served through the Mendon and Caledonia gate stations. Currently the Company has to balance daily loads between Mendon and Caledonia to assure that the distribution system is adequately served (See Appendix D).

The description of assets is subject to change as the Company is simultaneously offering any and all assets in an "Open Season" bidding process. This Open Season is being made available to many companies along the transportation routes, and the goal is to eventually shrink the transportation and storage assets to drive down the city gate costs while buying gas in the market areas. To the extent that the Open Season changes the capacity that will be awarded to successful suppliers, short-listed bidders will be so advised and given an opportunity to refresh bids.

RG&E's contracts with CNGT expire April 1, 2001. To the extent that the Company elects to alter its current contracts with CNGT, short listed bidders will be notified and given an opportunity to refresh their bids as noted above. Bidders whose bids rely on less CNGT capacity or storage than that shown in this RFP should include a description of their assumptions as part of bid submissions.

In addition to capacity entitlements, the Company also has certain long-term gas supply commitments for base load purchases. These supply contracts have Gulf of Mexico receipt points and will be assigned on a pro rata basis to winning bidders on a must take basis as part of the overall portfolio of assets assigned. The Company will make arrangements to keep suppliers whole in regard to any reservation fees paid under such contracts above applicable first of the month Index (see Appendix E).

The Company has given notice of termination to Tennessee Gas Pipeline and Texas Eastern effective November 1, 2000. It is anticipated that the suppliers will hold transportation contracts to RG&E's city gates as the Company works through the migration process. For reasons discussed below, RG&E will give notice to terminate contracts, as they expire, except for some portion of the CNGT capacity which will be retained for system balancing. RG&E's load is subject to migration from sales to transportation. The Company's current estimate of migration from RG&E retail sales to third party service providers is show in Appendix H.

B. <u>SERVICES REQUIRED AND TERMS OF SERVICE</u>

The Company will require the following items in final contracts negotiated with winning bidders:

1. Firm Sale of Natural Gas at the City-Gate

Sales shall be firm with delivery points at RG&E's Caledonia and Mendon city-gates. Suppliers will be responsible for all upstream storage and transportation nominations and the administration of all necessary upstream contracts. Upon expiration of RG&E's current capacity contracts, each supplier shall be responsible for entering into its own arrangements to effectuate deliveries.

2. Quantities

The Company's current retail design day requirements for sales customers are 365,000 dt/peak day. Suppliers are free to bid for any amount up to the design day, but not less than 50,000 dt/peak day. The Maximum Daily Quantity (MDQ) awarded to a selected supplier shall be split between Mendon and Caledonia to correspond to operational constraints on the Company's distribution system. Since on a design day, at most 47% of the gas can be delivered through the Mendon station, suppliers will be required to split their deliveries between Caledonia and Mendon. In addition, operational constraints necessitate splitting total system deliveries between Mendon and Caledonia off-peak. (See appendices D and G)

The Company will designate a lower MDQ for suppliers at the start of each contract year to account for migration of customers from sales to transportation. In the event that the total MDQ under all such arrangements is greater than the Company's revised peak day, RG&E shall reduce MDQ's for such Suppliers pro rata. Although actual MDQs will be based on RG&E's actual migration experience, the Company believes that the migration pattern shown in Appendix H is a reasonable projection based on current information. Although actual migration patterns may ultimately vary from these projections, bidders are encouraged to use this projection in developing bids, and as such bids will be evaluated accordingly.

On a daily basis, RG&E will nominate to all successful bidders under this RFP on a pro rata basis. Each Supplier's nomination shall be the ratio of Supplier's MDQ to peak day sales times estimated send-out. In that manner, each successful bidder will receive a share of RG&E's total annual market equivalent to its proportionate share of RG&E's peak day obligation.

Appendix G shows a hypothetical allocation among three suppliers and how capacity, market share and daily deliveries will be calculated.

3. Capacity Assignment

RG&E shall assign each successful bidder a pro rata portion of all transportation and storage assets currently under contract. Suppliers will be responsible for all charges that would normally be the responsibility of RG&E. Suppliers are free to make their own arrangements with transporters after the expiration of current contracts, except as noted below in regards system balancing. Suppliers are free to assign or renegotiate any and all contracts assigned to them by RG&E if such contracts expire during the term of the underlying sales contract. Both of the above are subject to Company's express written consent, such consent to be not unreasonably withheld, and the respective pipeline's tariff and contracts. In general, it is not the Company's intent to question the decisions of bidders regarding the level and types of transportation capacity needed to provide reliable service. However, arrangements entered into by bidders must be such that RG&E can effectively use or replicate them in the event that the contract is cancelled for cause. RG&E, prior to executing a final contract and periodically during the term of the contract, will require bidders to provide information on what assets will be used to serve RG&E to the extent bidders elect to use assets other than those assigned to them by the Company.

4. New York PSC Capacity Requirements

The New York PSC currently requires suppliers serving retail load to have sufficient firm primary capacity to serve such load for the five winter months. RG&E will require successful bidders under this RFP to meet this standard. The contract will include a re-opener in the event that current requirements are materially changed.

5. System Balancing

RG&E has historically required 60,000 dt/day of balancing services to accommodate the difference between actual and forecasted send-out, system imbalances, transportation balancing of end-use customers, etc. This requirement will be accomplished by intra-day nominations, by contracting for no-notice service on CNGT and having adequate storage inventory and capacity to make necessary injections and withdrawals on Critical Days when CNGT's system is under an OFO requiring forced balancing.

It is RG&E's intent to assign a pro rata share of its storage assets, including CNGT's no-notice service or similar service, to suppliers. The Company expects to retain the right to call upon sufficient capacity and storage to perform the balancing function when such capacity is required. However, as there is no certainty that a suitable mechanism will be available from pipelines and storage service providers to allow assignment of no-notice capacity to multiple suppliers, during the first contract year the Company will use alternative procedures in the interim.

Until such a mechanism is in place, RG&E will retain all CNGT storage in its own name and suppliers will be allowed to use such storage. Each day and during the day, as required, RG&E will consolidate all storage nominations of suppliers and make an aggregate nomination to CNGT. FERC's "Shipper must have Title Rule" will be addressed through waiver or other appropriate means. RG&E will require suppliers to maintain sufficient inventory to meet system-balancing requirements. Suppliers will be free to market their pro rata portion of storage capacity and deliverability, with RG&E effectuating any necessary releases. RG&E will invoice Supplier(s) each month for a pro rata share of 100% of CNGT's fixed no-notice service plus appropriate variable costs, until direct assignment of storage is possible. Bidders should factor this cost into all bids. The final contracts with bidders will contain details and alternative pricing once RG&E assigns storage directly to suppliers.

6. Storage Inventory

RG&E will assign any storage inventory to successful suppliers at cost, at the commencement of service under sales contracts on a pro rata basis. At this time, the Company estimates that (1/7th) 1.7 BCF will be in inventory on May 1, at an average cost using April Indices. Adjustments will be made to winning bids to the extent that this estimate deviates from actual.

7. Pricing

The Company requests that bidders submit bids for delivered service based on the arithmetic average of the settlement prices for the last three days of trading for the NYMEX natural gas contract. Although the Company prefers commodity premiums to fixed demand charges, bidders can split any premium above the Index on a commodity or demand charge basis. However, no more than 50% of such premium shall be in the form of a demand charge. RG&E is interested in quantifiable bids only. Consequently, RG&E will assign no weight to any proposed split of revenue generated by using assigned assets. Moreover, the Company requests that bidders not submit bids that flow through to RG&E any upstream demand costs (pipeline reservation rates, etc.) Bidders should submit bids in the form of NYMEX average plus numeric premiums and demand charges (See Appendix I – Bid Response Form).

Appendix I contains a bid form that bidders should use to summarize capacity and pricing information.

C. FORM OF CONTRACT

To the extent possible, RG&E prefers to use the GISB contract terms and conditions for supply arrangements. However, there are some areas where the sales contracts entered into under this RFP will differ materially from the GISB form contract. These are discussed below:

1. Force Majeure

Since suppliers will be assigned upstream capacity in order to effectuate procurement and delivery of gas to RG&E's city-gate, the Company does not believe that a supply failure in the supply area is grounds for force majeure. Force Majeure under this contract shall be applicable only if the pipeline delivering to the city gate from a liquid supply point, such as Dawn or CNGT South Point, declares force majeure. Supplier will be obligated to use best efforts to effectuate deliveries on other pipelines to avoid force majeure, with appropriate compensation terms included in the contract.

2. Penalties for Failure to Deliver

The penalty for failure to deliver, except for force majeure, shall be equal to the higher of Gas Daily CNGT North or the delivering pipeline's unauthorized daily overrun charge. In addition, RG&E will have the right to cancel the sales contract for material failures, including failure to deliver. However, RG&E will use its commercially reasonable efforts to acquire supply at prices lower than penalty rates and charge the supplier its share of the cost. Such penalties will only be required on Critical Days (extreme temperatures, pipeline OFOs mandating forced balancing, high send-out days, etc). On non-Critical Days, suppliers will be charged replacement costs.

3. Termination of Contract

Upon expiration of the contract or termination for cause, Supplier will return to RG&E all capacity originally assigned to Supplier pursuant to the contract, unless such capacity is held pursuant to a capacity contract whose original term has expired during the term of Supplier's sales contract with the Company. Supplier will retain any new capacity arrangements entered into after the expiration of the underlying assigned contracts. If bidders modify or renegotiate capacity contracts during the term of the sales contract, a decision shall be made at the time that the modification is made as to the disposition of the revised arrangement.

For sales contracts that expire prior to the expiration of the Company's storage contracts, the Company will purchase supplier's storage inventory at a mutually agreed-to Index price.

4. Liability

Each party will be liable for any penalties, fines or other costs arising out of its own negligence or misconduct and shall be held harmless from such charges arising out of the negligence or misconduct of the other.

D. TERM

Any contract for the services contemplated by this RFP will commence on May 1, 2000 and end March 31, 2001, or on March 31 of any subsequent year through 2008. The contract year for all years after the first year will be from April 1 through March 31. Other things being equal, RG&E will give preference to longer-term bids.

E. CONTENTS OF THE PROPOSAL

1. Proposal Contents

Each bidder must submit the following information:

(i) Three (3) years of financial statements and/or a current shareholders' Annual Report and 10K or equivalent for the corporate entity that will guarantee the RG&E sales contract.

(ii) A description of the bidder's credit clearances and credit levels on all pipelines with which RG&E has capacity that will be assigned pursuant to this RFP.

(iii) A completed copy of the enclosed Supplier Qualification Questionnaire.

2. Clarification of RFP

Potential respondents should review this RFP carefully to raise any questions as early as possible. The Company will attempt to answer all questions received in writing before Thursday, January 13, 2000 at 12:00 EST at a pre-bid conference to be held:

Date:	Tuesday, January 18, 2000
Time:	8:30 a.m. CST
Place:	Houstonian Hotel 111 North Post Oak Lane Houston, Texas

Address questions in writing to:

Robert Lauterbach
Fax: (716) 771-2825
Email robert_lauterbach@rge.com

3. Proposal Submissions

Six copies of the responses to the RFP must be enclosed in a sealed envelope, and sent to:

ROCHESTER GAS AND ELECTRIC
Attention: Judy Blake
Strategic Supply Management
89 East Avenue
Rochester, New York 14649
Phone (716) 724-8033

All proposals must be received by 5:00 PM Eastern Standard Time, February 3, 2000. The Company reserves the right to reject any proposal that is not complete in all material respects.

4. Responsive Proposals

RG&E is requesting proposals that are fully responsive to the requirements of this RFP. This includes but is not limited to the methodology set forth on pricing, quantities, capacity assignment, etc. In addition to each bidder's fully responsive proposal, the Company will consider alternate proposals, which would enable RG&E to achieve the objectives of the RFP.

F. CONFIDENTIALITY

The Company and its representatives shall take reasonable best effort steps to protect information that is clearly identified as confidential from disclosure to third parties. Bidders should understand that the Company might deem it necessary to disclose non-proprietary information regarding the RFP.

Upon request by a respondent, the Company shall request, in connection with any submission to the PSC or other authority having jurisdiction or oversight responsibilities for the Company's procurement activities, that information designated as confidential by the respondent be treated as confidential and proprietary in accordance with Commission's Trade Secret regulations (16 NYCRR S 6-1.3), and thus be protected from disclosure to third parties.

In no event shall the Company be liable for damage resulting from any inadvertent disclosure of confidential information during the period of review and analysis of proposals or during subsequent contract negotiations.

In the event that a potential respondent requires information from the Company that the Company deems confidential, the Company may provide such information but the potential respondent shall first execute a confidentiality agreement in a form to be provided by the Company.

G. PRELIMINARY ANALYSIS AND CONTRACT NEGOTIATIONS

The Company reserves the right to accept or reject any and/or all proposals, enter into negotiations with selected respondents, and to award the contract(s) to bidder(s) in such a manner as will in its sole opinion best meet the objectives described in this RFP. The Company may elect to delay all or part of the award schedule and to request rebids if necessary.

The Company will complete a preliminary analysis of all properly submitted proposals by February 25, 2000. Following the completion of the preliminary analysis, the Company will notify each respondent in writing with regard to the selection of a particular proposal for further negotiations.

The Company intends to actively pursue negotiations with "short list" candidates so that services may begin by May 1, 2000.

H. FIRM COMMITMENT

The Company shall not be considered to have made a commitment to purchase services or anything else from any respondent either through the issuance of this RFP, or through the initial selection of any proposal for final contract negotiations. The Company reserves the right, in its sole discretion, to discontinue negotiations with any or all potential suppliers prior to execution of an agreement. The Company also reserves the right to purchase services at any time from any source outside of the context of this RFP.

ROCHESTER GAS AND ELECTRIC CORPORATION

By: Clifton B. Olson
Print Name

Vice President of Energy Supply
Title

REQUEST FOR PROPOSALS
FOR
THE PURCHASE OF NATURAL GAS
AND RELATED ASSIGNMENT OF UPSTREAM CAPACITY

Enclosures:

Appendix A	**Listing of Assets**	**Pages 17 – 20**
Appendix B	**Diagram of Assets**	**Pages 21 – 23**
Appendix C	**List of Pipeline Web Sites**	**Page 24**
Appendix D	**City Gate Constraints**	**Pages 25 - 27**
Appendix E	**Gas Suppliers**	**Pages 28 - 29**
Appendix F	**Load Duration Curves**	**Pages 30 - 32**
Appendix G	**Hypothetical Supply Model**	**Pages 33 - 37**
Appendix H	**Forecasted Retail Requirements**	**Pages 38 - 39**
Appendix I	**Bid Response Form**	**Pages 40 - 41**
Appendix J	**Supplier Qualification Questionnaire**	**Pages 43 – 45**
Appendix K	**Bid Acknowledgement Form**	**Pages 46 – 47**

APPENDIX A

THE COMPANY'S CURRENT TRANSPORTATION AND STORAGE COMMITMENTS

CNGT – City Gate Assets

Rochester Gas and Electric Corporation

CITY GATE TRANSPORTATION AND STORAGE ASSETS (Contracted Volumes Adjusted for Releases/Assignments)

DEKATHERM - VOLUMES STATED AT CNGT INTERCONNECTS

CONTRACT	PIPELINE	ZONE OR LEG	EXP. DATE	RATE SCH.	RECEIPT POINTS	DELIVERY POINTS	4/1/00 - 10/31/00 MDQ	11/1/00 - 3/31/01 MDQ	4/1/01 - 10/31/05 MDQ	11/1/05 - 10/31/12 MDQ
100021	CNGT		03/31/01	FTNN	Cornwell	Caledonia City Gate	30,025	30,025		
100021	CNGT		03/31/01	FTNN	South Webster	Caledonia City Gate	18,326	18,326		
100021	CNGT		03/31/01	FTNN	Oakford	Caledonia City Gate	42,666	42,666		
100021	CNGT		03/31/01	FTNN	Lebanon	Caledonia City Gate	14,766	14,766		
100021	CNGT		03/31/01	FTNN	Leidy - Transco	Caledonia City Gate	9,413	9,413		
200103	CNGT		03/31/01	FT	Leidy - Tetco	Caledonia City Gate		20,500		
						Total CNG FT/FTNN	115,196	135,696		
700018	CNGT		03/31/01	FTNNGSS	Storage	Caledonia City Gate		141,994		
300084	CNGT		03/31/01	GSS		Injection - Less than 50% - 180 days	31,550	31,550		
300084	CNGT		03/31/01	GSS		Injection - More than 50% - 214 days	26,537	26,537		
300084	CNGT		03/31/01	GSS		Storage Capacity	5,678,994	5,678,994		
300084	CNGT		03/31/01	GSS		Withdrawal MDWQ	139,097	139,097		
400055	CNGT		03/31/01	GSS II		Injection - Less than 50%	1,094	697		
400055	CNGT		03/31/01	GSS II		Injection - More than 50%	921	586		
400055	CNGT		03/31/01	GSS II		Storage Capacity	197,006	125,392		
400055	CNGT		3/31/01	GSS II		Withdrawal MDWQ	2,897	1,844		
820	Tennessee	0/100	11/01/00	FT	See Attached List	CNGT @ Cornwell	9,754			
820	Tennessee	1/100	11/01/00	FT	See Attached List	CNGT @ Cornwell	1,000			
820	Tennessee	1/500	11/01/00	FT	See Attached List	CNGT @ Cornwell	13,519			
820	Tennessee	1/800	11/01/00	FT	See Attached List	CNGT @ Cornwell	6,452			
3915	Tennessee	0/100	11/01/00	FT	See Attached List	CNGT @ South Webster	3,282			
3915	Tennessee	1/500	11/01/00	FT	See Attached List	CNGT @ South Webster	9,795			
3915	Tennessee	1/800	11/01/00	FT	See Attached List	CNGT @ South Webster	5,677			
						Total Tennessee	49,479			
800370 R1	TETCO		10/31/00	FT	ELA	M1 - 30 24,828				
800370 R1	TETCO		10/31/00	FT	ETX	M1 - 24 3,518; M1 - TXG 1,252				
800370 R1	TETCO		10/31/00	FT	STX	M1 - TGC 828				
800370 R1	TETCO		10/31/00	FT	WLA	M1 - TXG 382; M1 - TGC 828				
800370 R1	TETCO		10/31/00	FT	M1-M2	CNGT @ Oakford	31,162			
						Total TETCO	31,162			
3943	Texas Gas	Zone SL	10/31/05	FT	Henry Hub 4,575; NGPL - Lowry 4,227; Mamou 4,228	CNGT @ Lebanon, OH	15,110	15,110	15,110	
						Total Texas Gas	15,110	15,110	15,110	
6506	Transco	Zone 3	10/31/12	FT	Utos TGPL	CNGT @ Leidy		9,425	9,425	9,425
6506	Transco	Zone 4	10/31/12	FT	Ragley TET	CNGT @ Leidy		208	208	208
						Total Transco		9,633	9633	9633
CITY GATE TOTALS (CNG FTNN + FTNNGSS)							115,196	277,690		

Empire – City Gate Assets

Rochester Gas and Electric Corporation									
CITY GATE TRANSPORTATION AND STORAGE ASSETS (Contracted Volumes Adjusted for Releases/Assignments)									
DEKATHERM - VOLUMES STATED AT INTERCONNECTS									
CONTRACT	PIPELINE	ZONE OR LEG	EXP. DATE	RATE SCH.	RECEIPT POINTS	DELIVERY POINTS	11/1/99 - 10/31/00 MDQ	11/1/00 - 3/31/01 MDQ	4/1/01 - 10/31/08 MDQ
18750	ANR	SE	10/31/08	FTS-1	SE Headstation	ANRPL Storage or Farwell	14,265	14,265	22,470
68750	ANR	SE	10/31/08	GF-1	SE Gathering Headstation	SE Gathering Headstation	14,265	14,265	22,470
25850	ANR	SW	10/31/08	FTS-1	SW Headstation	ANRPL Storage or Farwell	5,000	34,460	43,000
25900	ANR		10/31/08	FT-1	ANRPL Storage	Farwell (Muttonville and Capac)	111,600	111,600	151,200
33000	ANR Storage		10/31/08	FSS	Storage Capacity		6,228,915	6,228,915	8,432,435
33000	ANR Storage		10/31/08	FSS	Injection		31,110	31,110	42,149
33000	ANR Storage		10/31/08	FSS	Withdrawal		113,127	113,127	153,269
FT056	Great Lakes		10/31/08	FT	Farwell (Muttonville and Capac)	St. Clair	A)	A)	A)
FT067	Great Lakes		10/31/08	FT	Farwell (Muttonville and Capac)	St. Clair	B)	B)	B)
						Total Great Lakes	C)	C)	C)
SH 2939	TCPL - SH		10/31/08	FT	St Clair (2nd Parkway&Dawn)	Chippawa	102,959	102,959	102,959
SH 2937	TCPL - SH		10/31/08	FT	St Clair (2nd Parkway&Dawn)	Chippawa	35,674	35,674	35,674
						Total TCPL	138,633	138,633	138,633
95001	Empire State PL		10/31/08	FT	Chippawa	Mendon City Gate	172,500	172,500	172,500
CITY GATE TOTALS (EMPIRE STATE PL)							172,500	172,500	172,500
		A) 104,339 Winter / 0 Summer B) 56,222 Winter / 31,910 Summer C) 160,561 Winter / 31,910 Summer							
ANR Storage is an annual Unratchedted contract and injections and withdrawals can be made any day.									
If storage balance on April 1 >20% capacity, then the incremental amount will be reduced by the injection fuel rate (1.05%).									

Storage Notes:

ANR: -- Annual Storage Contract with no ratchets, daily injection and withdrawal any day of the year. For balances held in storage on April 1, greater than 20% of the MASQ, ANR will levy a 1.05 % fuel charge. Injections based on 214 days and withdrawals based on 55 days.

CNGT: -- Ratchet no-notice storage service. GSS transport reduces from 139,097dt to 128,000 dt at 35% full, 97,000 dt at 16% full and 87,000 dt at 10% full. GSSII transport reduced from 2,897 DT to 2,700dt at 25% full, 2,000 dt at 16% full, 1,800 dt at 10% full.

Summer injections based on 180 days less than 50% full, 214 days over 50% full. Winter injections are limited to 1/214 of the storage quantity.

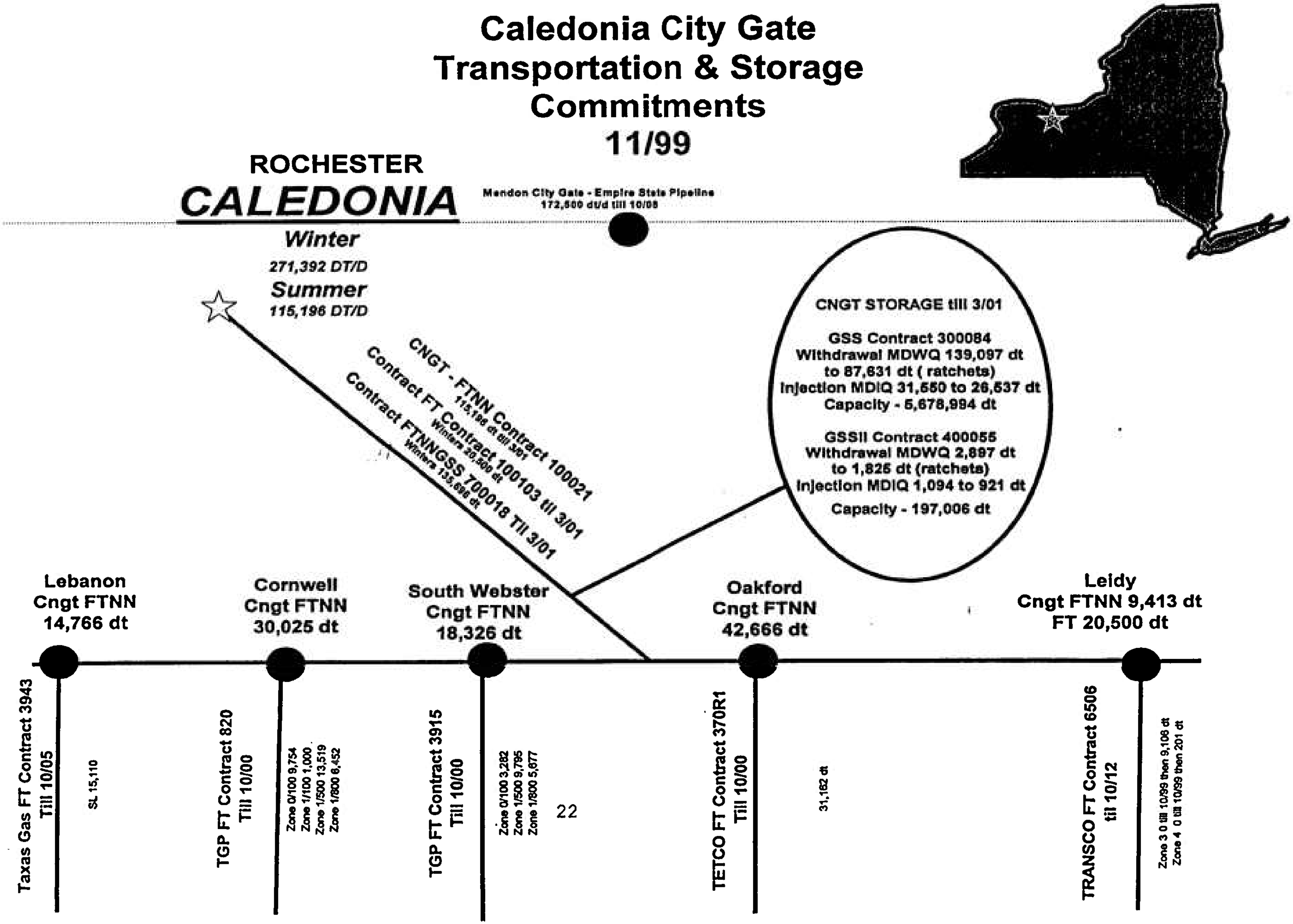
Minimum turnover equals November 1st balance – (25% of MASQ). Amount less than the minimum turnover will cost 2 times the fuel percentage.

APPENDIX B

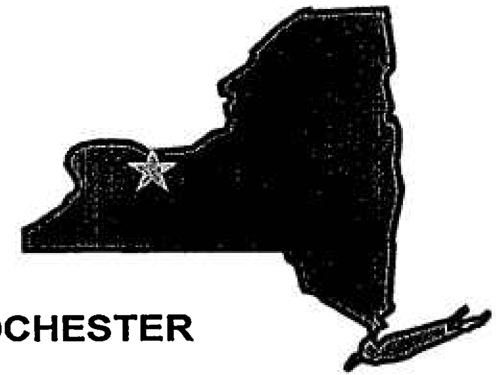
DIAGRAM OF THE COMPANY'S PIPELINE

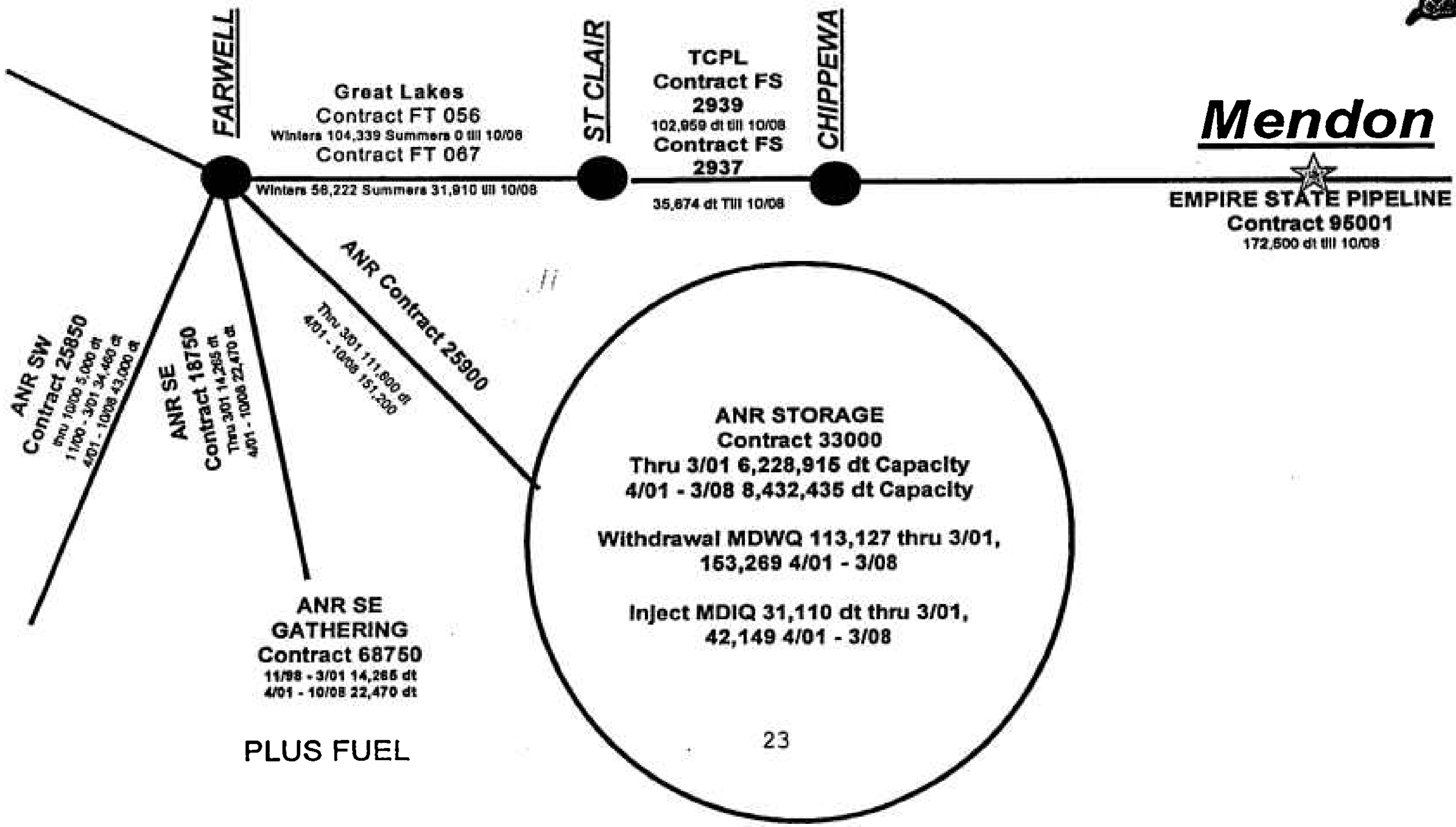
AND STORAGE COMMITMENTS

Caledonia City Gate Transportation & Storage Commitments 11/99



Mendon City Gate
Transportation & Storage
Commitments
11/99





APPENDIX C

WEB SITES

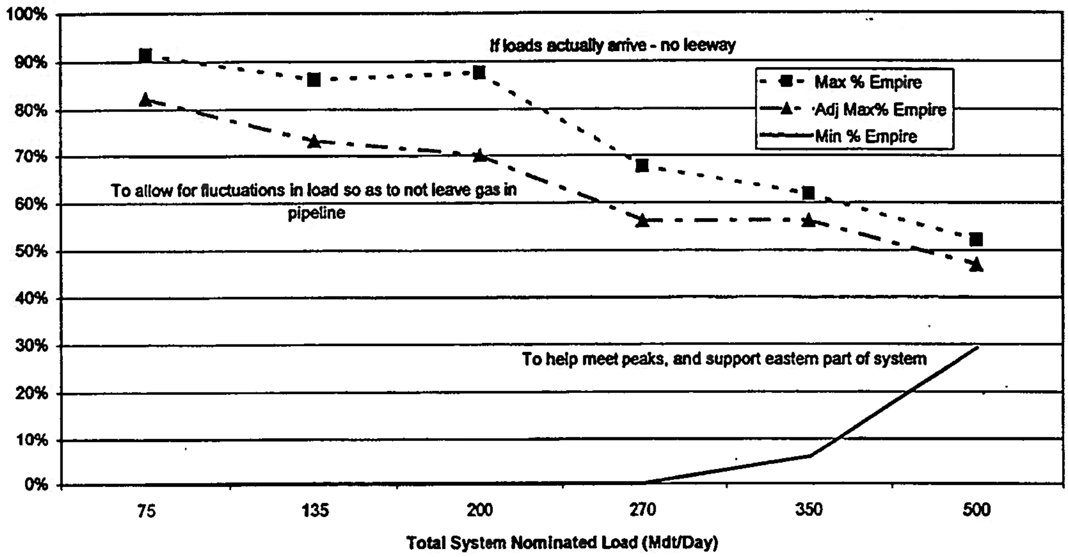
ANR	http://www.anrpl.com/
CNGT	http://www.cng.com/cngt/
Empire State	http://www.empirepipeline.com/
Great Lakes Transmission	http://www.greatlakesgas.com/
TCPL	http://www.transcanada.com/business/PDFTariff/index.html
Tennessee	http://www.epenergy.com/tgp/
TETCO	http://infopost.link.duke-energy.com/scripts/ndisapi.dll/TE/Home_Frame_TE
Texas Gas	http://www.gasquest.twc.com/
Transco	http://www.tgpl.twc.com/

APPENDIX D

CITY GATE CONTSRAINTS

Winter City Gate Constraints (November – April)

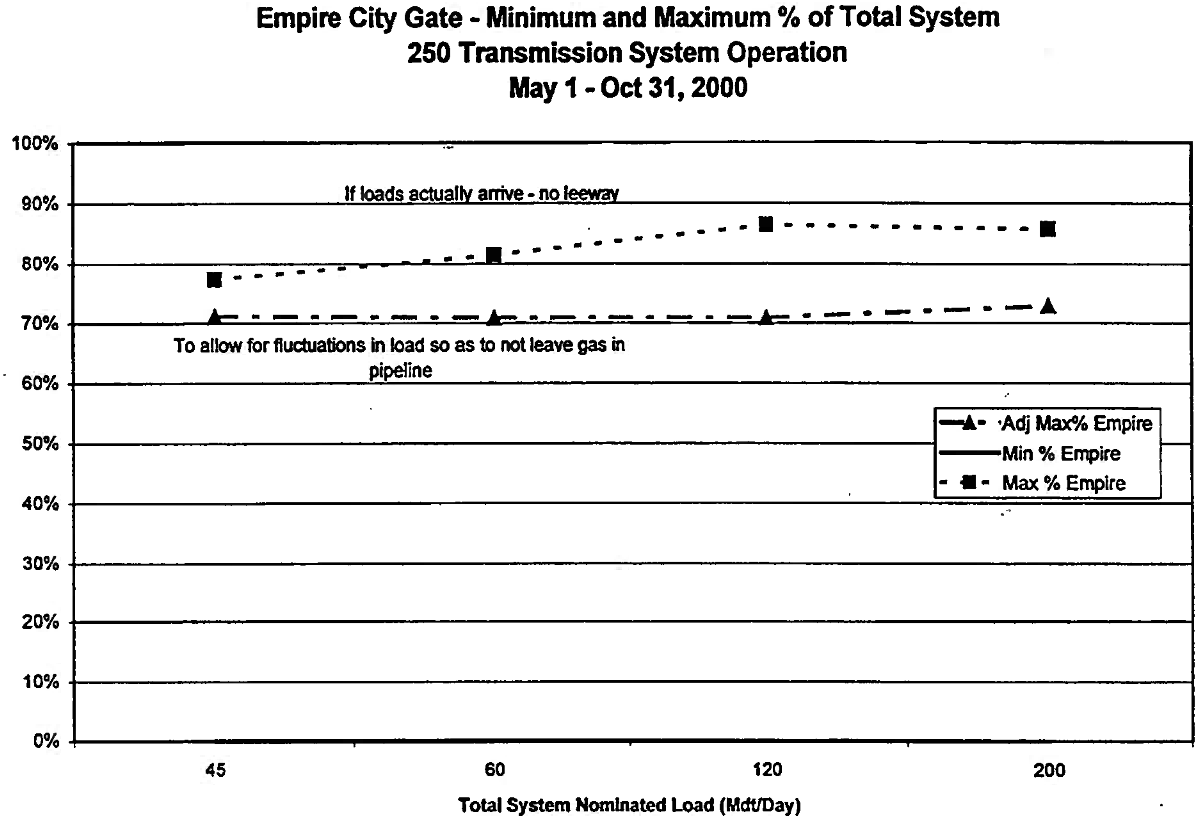
Empire City Gate - Minimum and Maximum % of Total System
350 psi/250 psi Transmission System Operation
November 1, 1999 - April 30, 2000



System Load Mdt	Percent Occurrence	Cumulative Percent	Minimum Empire	Maximum Empire	Minimum Caledonia	Maximum Caledonia
60-100	4.0%	4.0%	0%	82%	18%	100%
101-150	10.7%	14.6%	0%	73%	27%	100%
151-250	49.6%	64.2%	0%	70%	30%	100%
251-300	20.4%	84.7%	0%	56%	44%	100%
300-350	10.8%	95.5%	6%	56%	44%	94%
350-500	4.5%	100.0%	29%	47%	53%	71%

System Load Mdt	Minimum Empire Mdt	Maximum Empire Mdt	Minimum Caledonia Mdt	Maximum Caledonia Mdt
60-100	-	82	18	100
101-150	-	110	41	150
151-250	-	175	75	250
251-300	-	168	132	300
300-350	21	196	154	329
350-500	145	235	265	355

Summer City Gate Constraints (May – October)



System Load Mdt	Percent Occurrence	Cumulative Percent	Minimum Empire	Maximum Empire	Minimum Caledonia	Maximum Caledonia
30-45	12.1%	12.1%	0%	71%	29%	100%
46-60	49.8%	61.9%	0%	71%	29%	100%
61-120	29.2%	91.1%	0%	71%	29%	100%
121-200	8.9%	100.0%	0%	73%	27%	100%

System Load Mdt	Minimum Empire Mdt	Maximum Empire Mdt	Minimum Caledonia Mdt	Maximum Caledonia Mdt
30-45	-	32	13	45
46-60	-	43	17	60
61-120	-	85	35	120
121-200	-	146	54	200

APPENDIX E

A REDACTED SCHEDULE OF THE COMPANY'S

CURRENT GAS SUPPLY COMMITMENTS

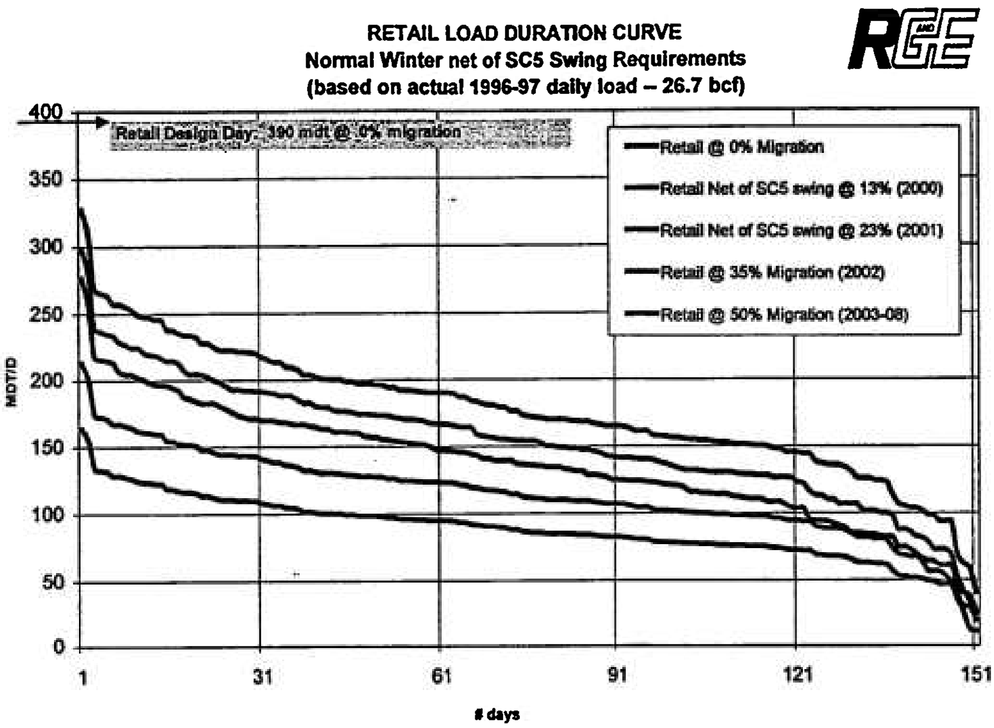
Summary of Gas Suppliers as of May 1, 2000

Supplier	Service	DT/day	Expiration Date
Amoco 365 days TETCO	Base Load (has 20 day recall May – October)	9,162	10/31/00
Engage 365 days TETCO	Base Load	9,600	10/31/01

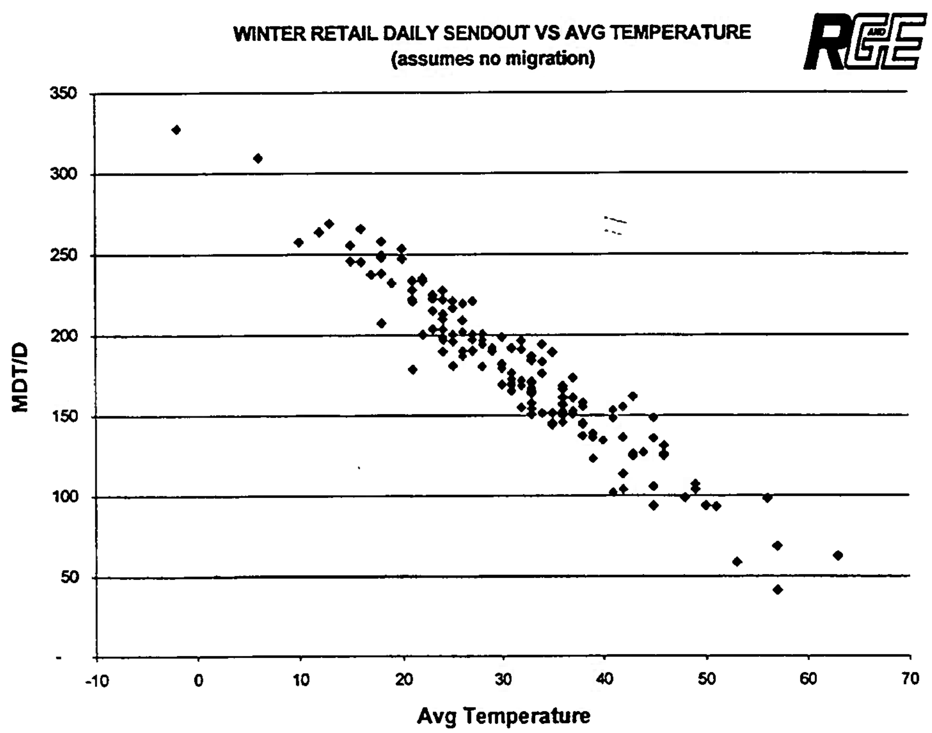
APPENDIX F

THE COMPANY'S CURRENT LOAD DURATION CURVE

Winter

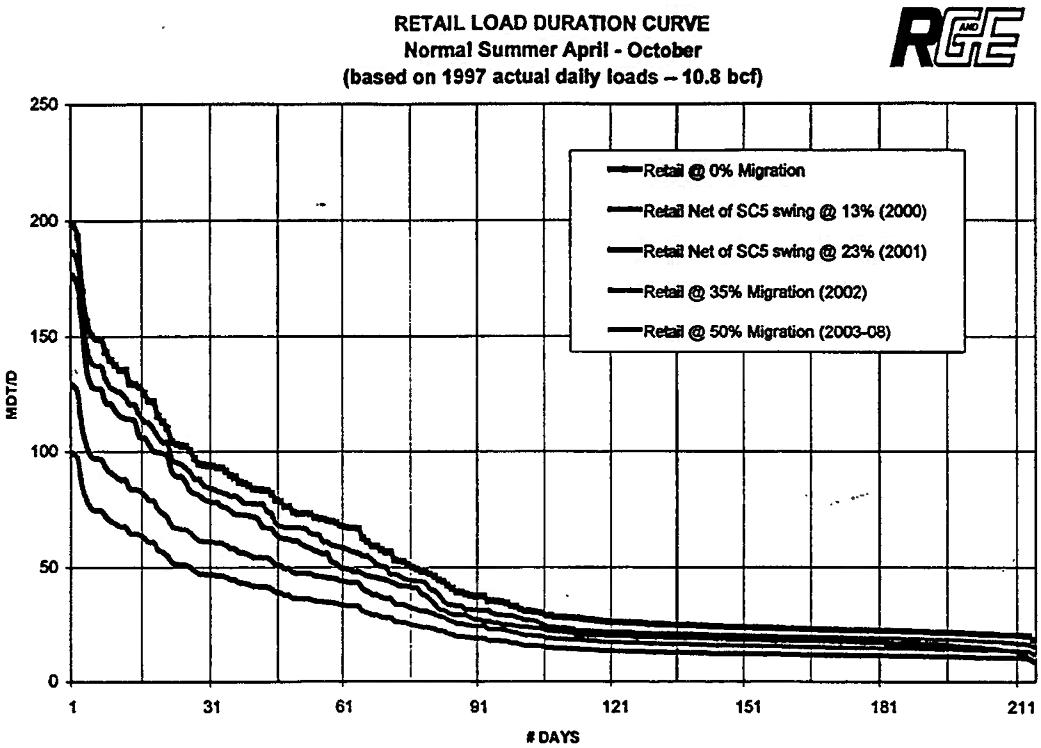


RETAIL LOAD DURATION CURVE
Normal Winter net of SC5 Swing Requirements
(based on actual 1996-97 daily load – 26.7 bcf)
Retail Design Day: 390 mdt @ 0% migration
Retail @ 0% Migration
Retail Net of SC5 swing @ 13% (2000)
Retail Net of SC5 swing @ 23% (2001)
Retail @ 35% Migration (2002)
Retail @ 50% Migration (2003-08)
MDT/D
400
350
300
250
200
150
100
50
0
1
31
61
91
121
151
days

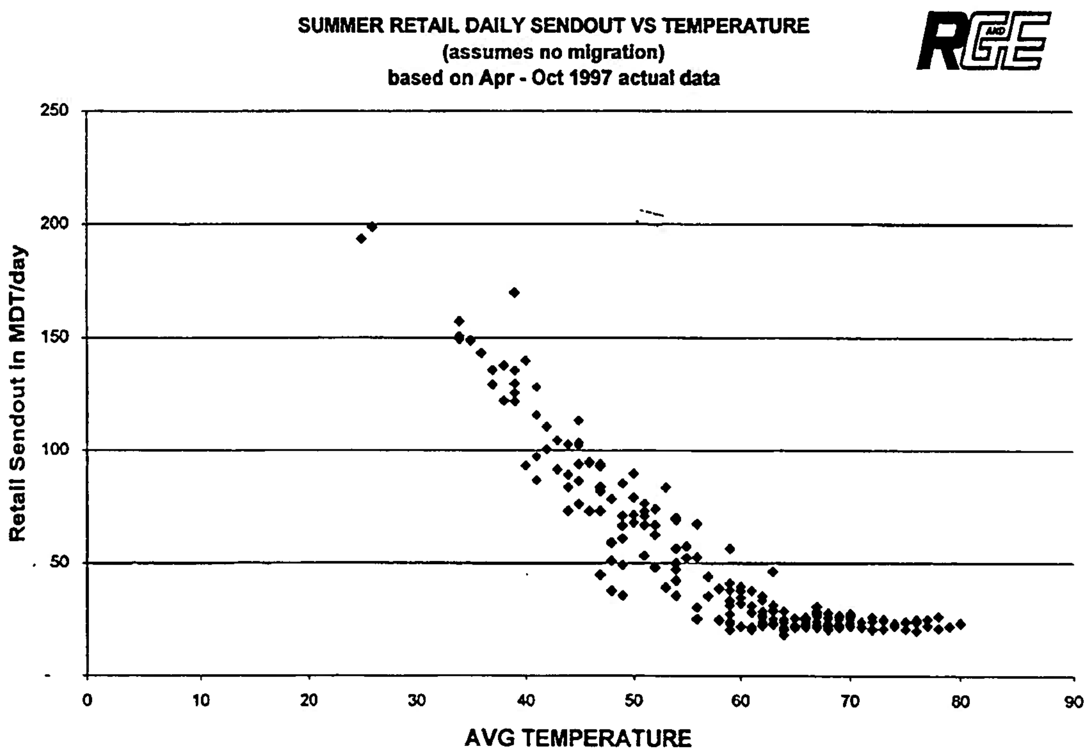


WINTER RETAIL DAILY SENDOUT VS AVG TEMPERATURE
(assumes no migration)
MDT/D
350
300
250
200
150
100
50
-10
0
10
20
30
40
50
60
70
Avg Temperature

Summer



RETAIL LOAD DURATION CURVE
Normal Summer April - October
(based on 1997 actual daily loads -- 10.8 bcf)
Retail @ 0% Migration
Retail Net of SC5 swing @ 13% (2000)
Retail Net of SC5 swing @ 23% (2001)
Retail @ 35% Migration (2002)
Retail @ 50% Migration (2003-08)
MDT/D
DAYS



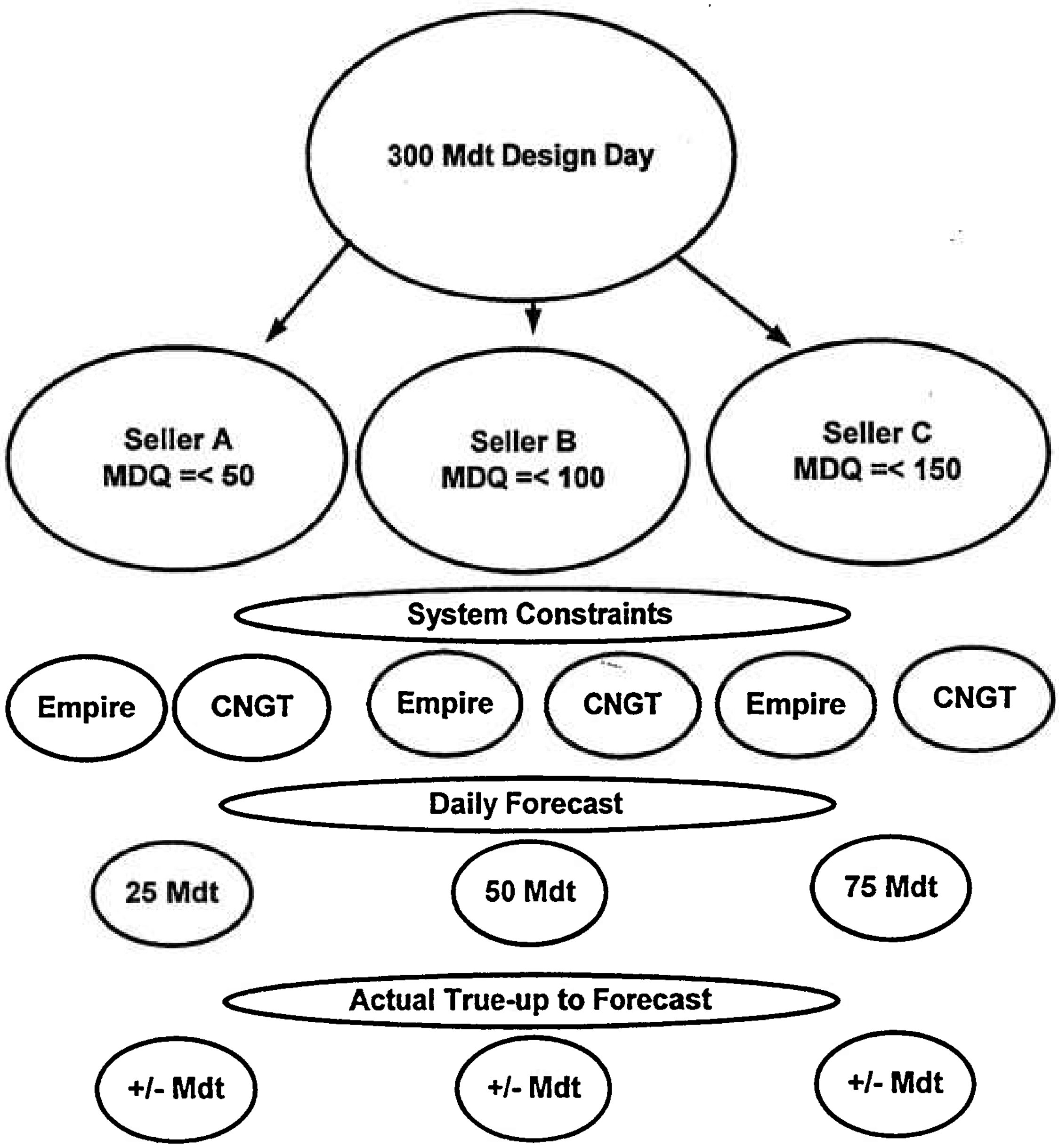
SUMMER RETAIL DAILY SENDOUT VS TEMPERATURE
(assumes no migration)
based on Apr - Oct 1997 actual data
Retail Sendout in MDT/day
AVG TEMPERATURE

APPENDIX G

HYPOTHETICAL SUPPLY MODEL

SHOWING CAPACITY ALLOCATION

Hypothetical Split
3 - Supplier Model



Example of 3-Suppliers on CNG

Rochester Gas and Electric Corporation

Example of Allocation Process for Three Suppliers

DEKATHERM - VOLUMES STATED AT CNGT INTERCONNECTS

CONTRACT	PIPELINE	ZONE OR LEG	EXP. DATE	RATE SCH.	RECEIPT POINTS	DELIVERY POINTS	11/1/00 - 3/31/01 MDQ	Supplier 1 at 16.667%	Supplier 2 at 33.333%	Supplier 3 at 50%
100021	CNGT		03/31/01	FTNN	Cornwell	Caledonia City Gate	30,025	5,004	10,008	15,013
100021	CNGT		03/31/01	FTNN	South Webster	Caledonia City Gate	18,326	3,054	6,109	9,163
100021	CNGT		03/31/01	FTNN	Oakford	Caledonia City Gate	42,666	7,111	14,222	21,333
100021	CNGT		03/31/01	FTNN	Lebanon	Caledonia City Gate	14,766	2,461	4,922	7,383
100021	CNGT		03/31/01	FTNN	Leidy - Transco	Caledonia City Gate	9,413	1,569	3,138	4,707
200103	CNGT		03/31/01	FT	Leidy - Tetco	Caledonia City Gate	20,500	3,417	6,833	10,250
						Total CNG FT/FTNN	**135,696**	**22,616**	**45,232**	**67,848**
700018	CNGT		03/31/01	FTNNGSS	Storage	Caledonia City Gate	141,994	23,666	47,331	70,997
300084	CNGT		03/31/01	GSS		Injection - Less than 50% - 180 days	31,550	5,258	10,517	15,775
300084	CNGT		03/31/01	GSS		Injection - More than 50% - 214 days	26,537	4,423	8,846	13,269
300084	CNGT		03/31/01	GSS		Storage Capacity	5,678,994	946,518	1,892,979	2,839,497
300084	CNGT		03/31/01	GSS		Withdrawal MDWQ	139,097	23,183	46,365	69,549
400055	CNGT		03/31/01	GSS II		Injection - Less than 50%	697	116	232	348
400055	CNGT		03/31/01	GSS II		Injection - More than 50%	586	98	195	293
400055	CNGT		03/31/01	GSS II		Storage Capacity	125,392	20,899	41,797	62,696
400055	CNGT		3/31/01	GSS II		Withdrawal MDWQ	1,844	307	615	922
3943	Texas Gas	Zone SL	10/31/05	FT	Henry Hub 4,575; NGPL - Lowry 4,227; Mamou 4,228	CNGT @ Lebanon, OH	15,110	2,518	5,037	7,555
						Total Texas Gas	15,110	2,518	5,037	
6506	Transco	Zone 3	10/31/12	FT	Utos TGPL	CNGT @ Leidy	9,425	1,571	3,142	4,713
6506	Transco	Zone 4	10/31/12	FT	Ragley TET	CNGT @ Leidy	208	35	69	104
						Total Transco	9,633	1,606	3211	4817
CITY GATE TOTALS (CNG FTNN + FTNNGSS)							277,690	46,282	92,563	138,845

Example of 3-Suppliers on Empire

Rochester Gas and Electric Corporation										RG&E
Example of Allocation Process for Three Suppliers										
DEKATHERM - VOLUMES STATED AT INTERCONNECTS										
CONTRACT	PIPELINE	ZONE OR LEG	EXP. DATE	RATE SCH.	RECEIPT POINTS	DELIVERY POINTS	11/1/00 - 3/31/01 MDQ	Supplier 1 at 16.667%	Supplier 2 at 33.333%	Supplier 3 at 50%
18750	ANR	SE	10/31/08	FTS-1	SE Headstation	ANRPL Storage or Farwell	14,265	2,378	4,755	7,133
68750	ANR	SE	10/31/08	GF-1	SE Gathering Headstation	SE Gathering Headstation	14,265	2,378	4,755	7,133
25850	ANR	SW	10/31/08	FTS-1	SW Headstation	ANRPL Storage or Farwell	34,460	5,743	11,487	17,230
25900	ANR		10/31/08	FT-1	ANRPL Storage	Farwell (Muttonville and Capac)	111,600	18,600	37,200	55,800
33000	ANR Storage		10/31/08	FSS	Storage Capacity		6,228,915	1,038,173	2,076,284	3,114,458
33000	ANR Storage		10/31/08	FSS	Injection		31,110	5,185	10,370	15,555
33000	ANR Storage		10/31/08	FSS	Withdrawal		113,127	18,855	37,709	56,564
FT056	Great Lakes		10/31/08	FT	Farwell (Muttonville and Capac)	St. Clair	104,339	17,390	34,779	52,170
FT067	Great Lakes		10/31/08	FT	Farwell (Muttonville and Capac)	St. Clair	56,222	9,371	18,740	28,111
						Total Great Lakes	160,561	26,761	53,520	80,281
SH 2939	TCPL - SH		10/31/08	FT	St Clair (2nd Parkway&Dawn)	Chippawa	102,959	17,160	34,319	51,480
SH 2937	TCPL - SH		10/31/08	FT	St Clair (2nd Parkway&Dawn)	Chippawa	35,674	5,946	11,891	17,837
						Total TCPL	138,633	23,106	46,211	69,317
95001	Empire State PL		10/31/08	FT	Chippawa	Mendon City Gate	172,500	28,751	57,499	86,250
CITY GATE TOTALS (EMPIRE STATE PL)							172,500	28,751	57,499	86,250

Example of 3 – Supplier Model

And Constraint Process

				Supplier 1	Supplier 2	Supplier 3	Total
1. MDQ Allocation of Capacity Process Based On Design Day				50	100	150	300
			Percent of total	0.166666667	0.333333333	0.5	
2. Winter System contraints for 150 Mdt day - Percents							
	Minimum	Maximium					
Mendon	0%	70%		0%	35%	65%	
Caledonia	30%	100%		100%	65%	35%	
3. Nominiation Proces	Mdt Nominations =	150	Mendon	-	17.500	48.750	66.250
			Caledonia	25.000	32.500	26.250	83.750
			Total	25.000	50.000	75.000	150.000
4. Actual True Up Process	actual =	130	Mendon	-	15.167	42.250	57.417
(Next Day)			Caledonia	21.667	28.167	22.750	72.583
			Total	21.667	43.333	65.000	130.000
Variance +/- CNG Storage =			Total	(3.333)	(6.667)	(10.000)	(20.000)

APPENDIX H

Forecasted

Retail Requirements and Migration Levels

Retail Requirements and Migration Levels

		Nov 1 1999	Nov 1 2000	Nov 1 2001	Nov 1 2002 - 2008
Month	Retail (no migration)	13% migration	23% migration	35% migration	50% migration
Annual Total	36,746,445	32,143,408	28,448,763	24,015,190	18,473,223
Winter	27,171,046	23,725,810	20,998,706	17,726,180	13,635,523
Summer	9,575,399	8,417,597	7,450,057	6,289,010	4,837,700
Peak Day	390	339	300	254	195
SC5 Peaking		25	45	anticipated tariff change	
Total Peak Day	390	365	345	254	195

APPENDIX I

Bid Response Form

Rochester Gas and Electric Corporation

Response to Firm Gas Supply RFP 6008

From: ______________________________

Contact: _______________ Phone: ___________
E-mail Address: ___________________________
Alternate Contact: _________________________

Name of Company that will execute the contract ____________________

Company that will guarantee contract (if different) __________________

Term of Bid: Starting Date ______________________

Ending Date ______________________

MDQ of Bid: ____________________ (in Dth/day)

Commodity Premium over NYMEX 3 Day Close: _______________ (in cents per dth)

Demand Charge: ____________________ (in cents per day per dth of MDQ)

Notes/Clarifying Remarks/Reservations or Contingencies:

____

____

____

____

____

____

____

APPENDIX J

Supplier Qualification Questionnaire

Supplier Qualification Questionnaire Page 1 of 3

1. Supplier Name:______________________________

   Address:______________________________

   Contact Name:____________________Phone:______________

   Corporate Headquarters Address:__________________________

2. Corporate Structure:
   2.1 Type of organization
      Corporation_____, Public_____, Private_____,
      Proprietorship____, Partnership_____,
      Other________________

   2.2 Date company starts business:____________________

   2.3 Subsidiary of ________________________________

3. Management <u>(please provide an organization chart)</u>
   3.1 Officers
      Chief Executive Officer_______________________
      President ________________________________
      Division Manager____________________________
      Marketing/Sales Manager_____________________
      Other_____________________________________

   3.2 Area Marketing / Sales Rep.____________________
      Address__________________________Phone___________

4. Financial
   4.1 Please submit with this questionnaire your latest annual report, and financial statements.

   4.2 Dun and Bradstreet number____________

   4.3 List five (5) largest accounts________________________
   ____

   4.4 General terms of sales______________________________

4.5 List credit references________________________________

4.6 Duff and Phelps Credit Rating:______as of ____________.

5. Labor

5.1 Describe staffing (producers; marketing and production staff; brokers and marketers, marketing)_____________________

5.2 Is company unionized?__________ Affiliation___________
Union Contract expiration___________________________

5.3 Have there been any supply disruptions in the past ten (10) years due to labor problems. If so describe______________
____

5.4 Does your company comply with the provisions of title VII of Civil Rights Acts of 1964 and the Equal Employment Opportunity clause of Executive Order No. 11246?_______yes ______no

6. Supply/Portfolio Information:

a. Natural Gas Physical Volumes
(Total - BCF/Day_______as of ____________):
(Others - BCF/Day_______ Own - BCF/Day_________):

Total - East____Mid-Con____West____Canada____

BCF/ Day own Production included above_____________:

b. Number of current supply deals by type:

	Industrials/ Co-generators	LDCs
Less than 5,000 dt/d	_________	_______________
5,001 - 10,000 dt/d	_________	_______________
More than 10,000dt/d	_________	_______________
Totals	_________	_______________

c. Experience - Number of Current Supply Deals as of ________

	Term Supply	Storage Management
Less than 5,000 dt/d	________	________________
5,001 - 10,000 dt/d	________	________________
More than 10,000dt/d	________	________________
Totals	________	________________

d. Number of asset/portfolio deals____________as of____________.
Small <2BCF____ Medium 2 - 10 BCF____Large >10 BCF ____

7. Does your firm qualify as a Minority Owned Vendor? ____Yes___No

A minority - owned business is at least 51% owned, operated and controlled by one or more persons belonging to one or more of the following protected groups: African Americans, Hispanic Americans, Oriental Americans, Native American Indians, American Eskimos, American Aleuts, or East Indians. A woman - owned business is at least 51% owned, operated and controlled by a woman or women. "Operated" in this context means being actively involved in the day - to - day management of the business. "Controlled" in this context means exercising the power to make policy decisions for the business.

Provide the basis for qualification

8. Please attach any additional pertinent information which you feel will assist in our evaluation of your capabilities.

Prepared by:____

Title:____

Date:____

Signature:____

Appendix K

Bid Acknowledgement Form
(To be faxed back)

Rochester Gas and Electric Corporation

Bid Acknowledgement Form

RFP No. 6008

Product/Service Description: Purchase of Natural Gas and Related Assignment of Upstream Capacity

This is to acknowledge receipt of RG&E's bid package identified by the RFP number.

Check one box

- We will submit a bid by the required due date. ☐
- We will not submit a bid by the required due date. ☐

If not submitting, please give a reason: ______________________

Any other comments: ____

____

____

Return this form as soon as possible to Robert Lauterbach at the following fax number: (716) 771-2825.

If you have any questions, contact Robert Lauterbach at (716) 724-8753.

Bidder's Company Name ______________

Person Responding ______________
Title ______________

Date ______________

APPENDIX P

QUESTIONS AND ANSWERS REGARDING REQUEST FOR PROPOSALS

RG&E RFP (THE PURCHASE OF NATURAL GAS AND RELATED ASSIGNMENT OF UPSTREAM CAPACITY)

1. Please provide historical loads on a daily basis for at least the last 4 years (prefer electronic format). ***RG&E will provide on computer disk***
2. Please provide information enabling us to project the decline in customer base and related sales due to migration through the year 2008. ***RG&E expects its retail access program to facilitate customer migration from retail sales service to transportation service. Therefore, the load forecasts provided in this RFP reflect a rather aggressive transition during the first three years with the load tapering off to approximately 50% around 2003. Beyond 2003, it is expected that the remaining retail load will consist primarily of residential customers who will chose to stay with regulated service.***
3. Please identify firm customer load by class (ie: residential, industrial, commercial). ***Most of the retail requirements are residential spaceheating. The breakdown by class as of 12/1/99 is as follows:***

   Residential: 84.4%
   Commercial: 12.5%
   Industrial: 1.6%
   Municipal 1.5%
4. Will supplier be entitled to serve interruptible load? ***No, see questions 5.***
5. Please identify interruptible customer load if supplier will be responsible for that load. ***RG&E has few dual-fuel and no interruptible customers that the supplier***

will be responsible for. The few dual customers are transportation customers, and not retail customers.

6. Are any of the capacity contracts contained within the RG&E portfolio 7C? If so, please identify these contracts. Are any of the contracts non-releaseable? ***All our capacity is part 284, except Empire and TCPL, which are assignable with consent since no EBB mechanism is in place on these systems.***

7. Please provide history of peak day occurrences.

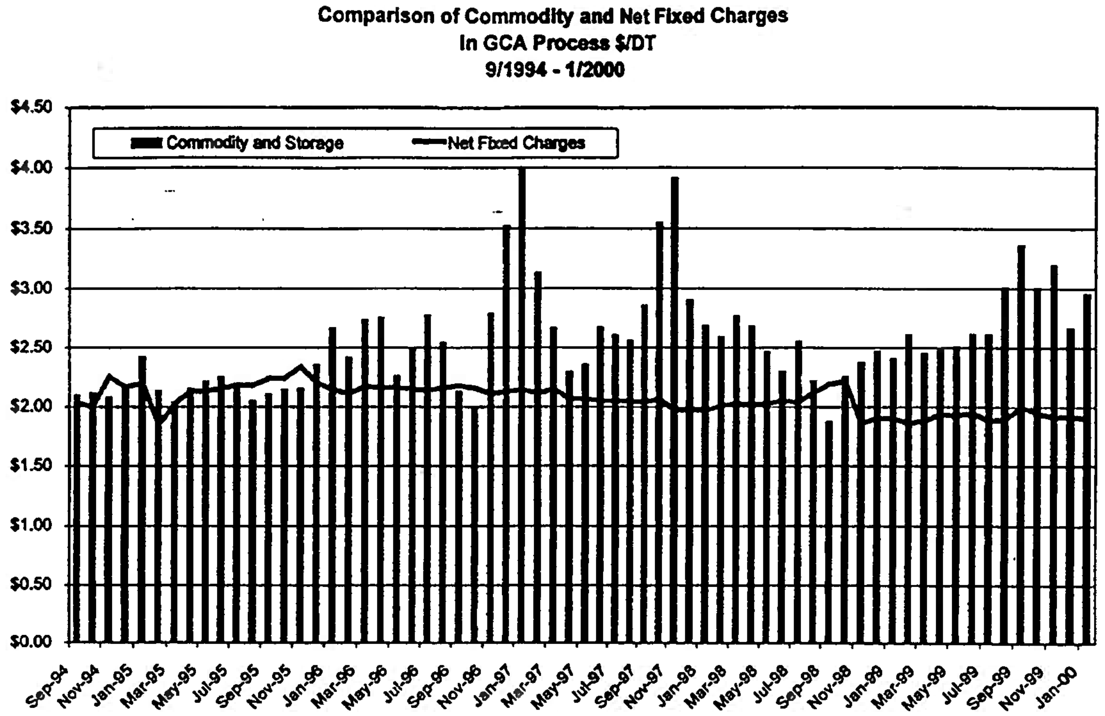
Actual Retail Peak Day
1996 = 360 Mdt
1997 = 328
1998 = 269
1999 = 306

8. Please provide all data contained in Appendix F,G and H in the RFP in electronic format. ***RG&E will provide on computer disk***

9. Please provide all tariff information, including rates, fuel and applicable surcharges, associated with all contracts (prefer electronic format excel).

RG&E will provide on computer disk

10. Please provide last 3 to 5 years of state filed PGA's/EGC's. ***RG&E's monthly GCA process is based on the PSC Regulations which uses current rates applied to annualized volumes. RG&E's GCA has been influenced by a 1995 rate case settlement process which shifted costs among years during its 3-years term. The chart below shows the demand and commodity components of the GCA – average cost of gas filed in the PGA. It is our objective that the supplier (s) chosen in this RFP process will lower both of these components.***



11. How often are these (PGA's/EGC's) filed with the state? *Monthly*

12. Please provide all known information regarding regulatory proceedings (state and FERC) on contracted pipelines which may have a positive or negative impact on future rates related to those pipelines. ***RG&E expects participants in this process will inform themselves of this type of information as it pertains to FERC. With regard to State proceedings, the New York Public Service Commission is encouraging LDCs to exit the merchant function and not to contract for additional capacity. The specific impact of this policy, if any, on pipeline rates can not be determined, but RG&E believes it is negligible.***

13. Does the company know of any impending refunds or surcharges on these pipelines ? ***Yes, there are pending surcharges on ANR, which should be very small. The precise amount is not applicable.***

14. How will refunds and surcharges be handled during the term of the release? ***Any refund or surcharge will be the responsibility of the assignee, for any period the assignee held RG&E capacity.***

15. Please provide additional detailed discussion on the issue of Mandatory Assignment of Capacity related to migrating customers. ***New York State does not have mandatory assignment.***

16. As migration occurs during the term of the release, will the capacity assigned to the supplier be automatically re-assigned to the migrating customer on a pro-rata basis thereby reducing the supplier(s) demand charges under this program? ***No***

17. Please provide ratchet information relative to all storage contracted by RG&E. ***See RFP package – page 20***

18. Does RG&E hold any LNG or LP-air assets? If so, how will these assets be handled with the supplier? ***No***

19. Please identify in detail the LNG and/or LP-air assets, if any. ***None***

20. Will RG&E accept bids that do not involve the assignment of RG&E's capacity contracts? ***No***

21. Will potential suppliers be allowed to revise bids subject to the results of the 12/21/99 Long Term capacity release RFP? ***Yes – for the short list round.***

22. Please provide all NYPSC rules and policies regarding mandatory assignment of capacity and capacity requirements needed to serve migrating load. ***RG&E***

expects participants in this process will inform themselves of this type of information. Please refer to the PSC web site http://www.dps.state.ny.us/. See in particular Orders issued in Cases 93-G-0932 and 97-G-1380.

23. Will RG&E terminate all contracts as they expire? ***Yes, with the exception of renewing a portion of CNGT storage for system balancing. See question 34.***

24. As the customer base declines over time due to migration, will suppliers be allowed to automatically assign their capacity to the migrating load? ***No.***

25. Will RG&E accept bids based upon their approved state filed rates allowed under their PGA/EGC? ***No. For bids to be acceptable, they must be quantifiable. Please refer to Pg. 13—Paragraph 4 – responsive proposals.***

26. Please identify all OBA's with pipelines/others. ***Empire***

27. Who will control OBA's under this program? ***RG&E will have to maintain so as to balance the system.***

28. Is RG&E an equity owner and/or shipper in any of the future pipeline expansion projects (Independence/Millennium/Vector/etc)? If not, do they plan to get involved contractually and how would that impact this program? ***No to both questions***

29. Please discuss demand charge component of bid structure as outlined on the Bid Response Form on Appendix I. ***Suppliers should take their total costs, including pipeline charges, and split them between demand charges and a commodity premium. No more than 50% of the premium may be billed to RG&E as a demand charge.***

30. Will RG&E assign capacity to the winning supplier at maximum tariff rates? If not, how will that be handled? ***No, due to confidentiality, we can not make public the discounted rates on ANR storage and Empire. Accordingly, we request that you assume maximum tariff rates in your responses. RG&E will assign its actual costs.***

31. Will RG&E allow suppliers to alter receipt and or delivery points of assigned capacity during the term of the release? ***As indicated in the RFP, it can be done with consent of RG&E.***

32. Pursuant to : SYSTEM BALANCING PARAGRAGPH 5 PAGE 7 AND 8 OF RFP; Please identify RG&E's annual cost associated with CNGT's fixed no-notice service plus appropriate variable costs. Does this cost include FT-NN capacity and storage or just storage? ***Based on RG&E current contractual terms and current tariff rates, the following table shows estimated annual costs associated with CNG storage through 3/31/01.***

CNG GSS and GSS II STORAGE through 3/31/01

Assume:	$ 2.60 commodity			
	Volume		**Rate**	**Estimated Annual Cost**
Deliverability	141,994	$	5.7580	$4,088,007
Capacity	5,876,000	$	0.0146	$1,027,910
Demand	141,994	$	1.9002	$3,237,853
Fuel	5.48%			$ 885,589
Inj/With	5,876,000	$	0.0577	$ 338,773
TOTAL ANNUAL COST				**$9,578,132**

33. Please discuss in detail the additional costs to the supplier for balancing. How much will the charges to the supplier be on a monthly basis? ***Please refer to individual pipeline tariffs.***

34. What is the annualized amount of the retained CNGT storage plus appropriate variables? This will enable the supplier to determine its pro-rata share of these over-all costs. ***After the current CNG contract expires on March 31, 2001, assume for bidding purposes that RG&E would renew for 60,000 mdt of FTNN-GSS deliverability and related capacity. The estimated cost for this service based on today's tariff rates is shown below:***

CNG GSS STORAGE FOR BALANCING 4/1/01					
Assume:	$	3.50 commodity			
	Volume		Rate		Estimated Annual Cost
Deliverability	60,000	$	5.7580	$1,727,400	
Capacity	2,460,000	$	0.0137	$ 404,424	
Demand	60,000	$	1.8533	$1,334,376	
Fuel	5.56%			$ 506,900	
Injection/Withdrawal	2,460,000	$	0.0289	$ 71,094	
TOTAL ANNUAL COST				**$4,044,194**	

35. Why should bidders summarize capacity on bid form if assignment is done on a pro-rata basis? ***The bid response form does not require you to summarize capacity.***

36. Please identify all applicable taxes that the winning bidder will be liable for as a participant in this program. ***Generally, if 50% or more of a supplier's New York State revenues are derived from the sale of Natural Gas in New York State, then that supplier would qualify as Section 186, Article 9 taxpaying utility and the***

tax would be 0.75% of revenues in New York Sate. (Please note that RG&E does not provide legal or tax advise, suppliers should seek independent advice.)

37. UNDER SUMMARY OF GAS SUPPLIERS AS OF 5/1/00: Are supply contracts supply or market area oriented? What is the duration of these contracts? What are the re-newal terms, if any, and what are associated cost structures? ***Amoco's supply contract will expire 10/31/00, and Engage's will terminate 10/31/01. Both contracts are of Gulf supplies contracts, and are priced at FOM indexes. RG&E will pay reservation charges.***

38. Please provide all primary receipt and delivery points of all contracts. ***See pages 18 and 19 of RFP. The Tennessee points were omitted, and have been attached to this presentation.***

39. Please provide all injection and withdrawal information related to the storage contracts and associated fuel and costs (fixed and variable). ***Pages 18 - 20 of the RFP outlines the MDQs. RG&E is providing rate information on disk.***

40. How will daily load requirements be determined and communicated to the supplier(s) in a timely manner in accordance with nomination deadlines on the delivering pipelines? ***By 9 am eastern time – day before, with updates as needed in a manner that permits timely nomination (RG&E has had a portfolio manager for six years, and this is not a problem).***

41. Are all existing RG&E customers able to migrate off-system? ***Yes, all customers can migrate off RG&E's system supply to wholesale markets. No customers have physically by-passed RG&E, however.***

42. If the supplier is eligible to serve interruptible load, please provide details of that customer base and their fuel switching capabilities. ***Please see question 5. The current transportation market is about 20 BCF.***

43. The RFP discusses that customers will be required to hold five months of winter capacity. How is the winter MDQ determined for migrating customers under this scenario? ***The supply contract MDQ under this RFP will be adjusted annually or seasonally as customers migrate. It will be the suppliers' responsibility to hold sufficient firm capacity, to meet retail peak load in each winter month.***

44. Please provide dates that capacity contracts expire through 2008. ***Please see pages 18 and 19 in RFP.***

45. Please provide a forecast of potential firm load growth through 2008. ***Assume total demand on RG&E facilities is flat.***

46. Please provide historical daily gas demand at Caledonia and Mendon citygate. If there was excess or insufficient demand at the two citygates, what was the amount of gas purchased or sold other than the source of Empire and CNGT?

RG&E's system is integrated, except for the Pavilion system. As a result, the company experiences a total demand requirement and not two separate demand requirements at Caledonia and at Mendon. Due to downstream constraints, the gas must be sourced from both Mendon and Caledonia. RG&E will, pursuant to this RPF, allow suppliers to deliver to the two city gates in any manner they see fit, subject to the system operating constraints. These constraints are outlined in Appendix D. Historical takes at the two city-gates were determined

in part by historical factors that are no longer applicable and more recent data is not readily available.

47. Please provide historical daily throughput and Gas Daily price at Farwell, St Clair, Chippawa, Lebanon, Cornwell, South Webster and Oakford. ***RG&E does not have daily historical information at these points.***

48. Please provide historical demand, variable and fuel costs from Chippawa, Farwell,St Clair to Mendon. Also from Lebanon, Cornwell, South Webster, Oakford, Leidy to Caledonia. ***RG&E does not have daily historical information at these points.***

49. Please provide daily storage injection, withdrawal and inventory level of GSS I & II on CNG, storage on ANR and associated demand, variable & fuel costs. ***Historical injections and withdrawals by day are not readily available and reflect marketing conditions at the time that decisions were made. RG&E will not require suppliers to fill or empty storage in any particular pattern as long as city-gate deliveries are made, peak day deliverability is maintained, and there is sufficient gas available for balancing, the latter only as long as RG&E holds the underlying storage contracts that support balancing. For rate information, see question 9.***

50. Please provide details, including rates, for any discounts on RG&E's transportation and storage contracts. ***Please use maximum tariff rates in RFP response***

51. Please provide details on any terms and conditions that restrict RG&E's ability to use its existing CNG capacity to receive gas from CNG South Pool versus the existing primary receipt points? ***RG&E has experienced no restrictions on its ability to receive gas from CNG South Pool.***

52. Please provide details, including rate impacts, of any terms and conditions that restrict RG&E's ability to utilize secondary receipt and delivery points on each of its various transportation and storage contracts. ***Only limitations are using ANR storage transport. Using other delivery points under that contract will increase costs. Please use maximum tariff rates in RFP response.***

53. Does CNG allow RG&E to deliver its CNG FTNNGSS capacity to points other than RG&E's city gate? ***Yes, but not on a no-notice basis.***

54. Does Great Lakes allow RG&E to deliver its FT capacity to points other than Muttonville and Capac? What limitations does Great Lakes impose on these secondary deliveries? ***ANR storage transport goes to these two points. No limitations are known on Great Lakes.***

55. Please provide details on any segmentation rights RG&E has on its ANR and Texas Gas long-haul capacity. ***Same rights as in the tariff.***

56. Please provide details on any OFO's typically imposed on RG&E by its various transportation and storage suppliers. For example, does CNG require RG&E to purchase the full 29,913 dth/day (FTNN @ 9,413 and FT @ 20,500) of Leidy sourced capacity in the winter? ***1. Valley gate restriction. Does not affect RG&E because it has the required south to north capacity. 2. X-56 Leidy OFO. RG&E is exempt from the X-56 Leidy OFO. 3. Hourly Limit Advisory –***

CNG issues four hour advance notice it might issue an OFO requiring RG&E to limit delivery fluctuations within one hour per its tariff.

57. Does ANR allow RG&E to deliver to secondary points and does the transportation rate change? ***Yes, SW and SE are at maximum tariff rates, as long as points are within path....i.e. ML 7..***

58. How has RG&E historically (or expect to) utilized the 20,500 dth/day of CNG FT capacity sourced at Tetco Leidy with no upstream capacity? Is this winter only capacity? ***Winter only capacity used for peaking.***

59. RG&E has more CNG Oakford take away capacity than upstream supply. How has RG&E typically utilized this excess capacity in the past? ***Used to bring up gas supplied at South Point.***

60. Why is RG&E proposing a 5/1 start date versus a 4/1 or 11/1 startdate? ***RG&E would prefer April 1, but we believe that the execution of the contracts may not occur within the relevant time frame. If we were to use November 1, we would be responsible for storage fill and suppliers would have to take assignment of gas. We believe that suppliers can get additional value by optimizing storage fill.***

61. What is the basis for the forecast of migration to unbundled service? Please provide data on the historical rate of migration experienced by RG&E. ***See question 2.***

62. Please provide details on the anticipated change to the SC5 tariff.

RG&E expects to modify its tariff to require suppliers who serve the SC5 transportation load to make daily nomination changes to meet daily forecasted requirements.

63. Please identify any RG&E capacity that is not covered under part 284 of the FERC rules. ***See question 6.***

64. Please clarify RG&E's proposal for adjusting the MDQ to account for migration. Specifically, does RG&E intend to reduce the delivery obligation of the supplier as customers migrate off system? ***Yes.*** Will this be a permanent reduction or does RG&E expect to be able to increase the MDQ at a later date should customers return to the system? Does RG&E expect to be able to increase the MDQ above the quantity of assets RG&E currently has available for system requirements? ***RG&E will not automatically increase MDQ if customers migrate from another supplier to RG&E.***

65. How does RG&E propose to address differences in the actual rate of migration and the projected rate used for developing the bid? ***RG&E will adjust contracts MDQ's for migration annually (or perhaps seasonally).***

66. Please clarify the proposed allocation process summarized in appendix G. Specifically: ***Suppliers will be subject to actual migration. Any risks or rewards should be factored into the premiums asked. This will be discussed further during final negotiations.***

67. The explanation provided in the text implies a pro rata distribution of requirements but the example does not distribute the Caledonia vs Mendon

obligations on this basis ***If the supplier takes 50 % of assets, then the pro rata share is 50% of everything..***

68. The RFP states the "RG&E will require suppliers to maintain sufficient inventory to meet system-balancing requirements." (p. 8). Please provide details on what RG&E considers sufficient inventory. ***Generally, system balancing is less than 60 Mdt per day, so a sufficient inventory would be enough gas to cover perhaps 5 days of imbalances.***

69. What April indice(s) should be used to price the May 1 inventory RG&E anticipates having in storage (i.e., Tetco, TGT, and other upstream plus variable to and into storage or CNG South). ***Assume $2.50 per dt. This cost will be trued up in April.***

70. With respect to the pricing, does RG&E expect to trigger prices for this deal on a monthly basis or does it expect to use the last three day settle for all months? ***3-day settlement, but subject to discussion.***

71. With respect to pricing, does RG&E expect to pay the same price for all deliveries regardless of source (i.e., storage w/d's or flowing)? ***Yes – city gate price***

72. Please provide pricing information on RG&E's two supply contracts, as well as delivery points. ***See question 37***

73. Terms and conditions covering the 20 days of recall on the Amoco supply ***20 day recall with 24 hours notice – any 20 days during May - October***

74. Why is the CNGT GSSII contract MSQ reduced to 125,392 DT from 197,006 DT as of 11/1/00? ***CNGT is eliminating its GSSII storage service and converting it to GSS storage.***

75. The ANR storage and transportation contract quantities increase. Why don't the downstream contracts on GLGT and TCPL increase accordingly?
As a result of prior portfolio restructurings, RG&E has mismatches between its downstream and upstream capacity. Specifically, Empire, TransCanada and Great Lakes contract restructurings resulted in permanent volume reductions while ANR rampdowns were only effective for a five-year period.

76. It is suggested in the RFP that RG&E has no mechanism to assign no-notice service to multiple suppliers. How about a single supplier? Would there be advantages to assign the portfolio to a single supplier? ***RG&E is interested in bids that supply the entire load. However, we will accept bids for lesser amounts. An advantage of a single supplier may be simplification of the process. In bid evaluation, we will weigh the administrative convenience of a single supplier versus the price and reliability of a portfolio of suppliers.***

77. Will preference be given to longer term bids? Up to how many years? ***Yes up to 8 years – October 2008, when asset contracts on the Empire side expire.***

78. In a multiple supplier model, please clarify how RG&E will handle swing loads and purchases, including intra-day nominations among multiple suppliers (i.e., designate one swing supplier, prorate or least cost)? ***In general, pro-rata.***

79. Please clarify RG&E's intent in transferring the storage inventory "at cost" as referenced at the top of Page 9. ***The intent is that the storage balances will be assigned just like the capacity. The costs will become part of the city gate price.***

80. Is the ANR contract #25900 (storage to Capac/Muttonville) a winter only agreement and can you go to other points in area ml7 with the unused capacity. ***The ANR service is limited to those delivery points. It is annual service.***

81. What ROFR process, if applicable is associated with the TETCO and Tennessee capacity turned back by RG&E. ***RG&E has issued termination notices to TETCO and TGP and therefore, has relinquished the capacity effective October 31, 2000, and its rights of First Refusal.***

82. Throughout the Request RG&E refers to capacity that will be assigned to the winning suppliers. Will the capacity be assigned to the suppliers or released to the suppliers via the appropriate pipelines capacity release provisions? ***By applicable release provisions.***

83. The Request references the New York PSC requirements that suppliers serving a retail load have sufficient firm primary capacity to serve such load for the five winter months. Please provide RG&E's interpretation of this requirement. ***See Question 22.***

84. The Request discusses System Balancing and requires suppliers to have adequate storage inventory to cover injections and withdrawals on Critical Days. Please define adequate. ***See Question 68***

85. The ANR and Empire contracts contain negotiated rates, which have not been disclosed in the RFP. In order to prepare a fully evaluated bid, we would appreciate RG&E disclosing these rates. ***See Question 30***

86. Can the primary delivery points be changed with regards to the ANR capacity? ***See Question 57***

87. Is there no CNG capacity which corresponds to the Texas Gas and Transco capacity after March 2001? ***Correct, See question 59***

88. Please outline the Pavilion load profile. ***See question 46***

89. Are any loads underlying RG&E's forecast interruptible? Under what circumstances are they interrupted? ***No. See question 5***

90. What assets does RG&E plan on retaining for system balancing? ***See question 68***

91. What are RG&E's directives from the NYPSC to provide customers with the ability to unbundle – notice period, required storage inventory transfer, timing of complete unbundling? ***See question 22***

92. Does RG&E intend to retain a portion of its existing CNG services beyond 3/01 to manage system balancing requirements?

    A) if so, what is the asset mix?

    B) If not, what daily, monthly, seasonal parameters does RG&E require for system balancing?

    See question 68

93. Which indices will be used to value RG&E's inventory gas in April? ***See question 69***

94. Will RG&E commit to purchase all supply requirements from the successful bidder or will RG&E also purchase spot market gas? ***RG&E will purchase the pro rata share of each contract holders MDQ to satisfy 100% of its requirement for resale.***

Contract Information

Service Package: 3915
Contract MDQ: 18754
Flow Date/Time: 07/02/1999 09:00
Requested Date/Time: 07/02/1999 11:16

Leg 100: 3282
Leg 500: 11012
Leg 800: 4460

TGP Receipt meters

Location Code	Meter Number	Meter Name	Meter Purpose	Meter Quantity	Meter Zone	Meter Leg	Meter Segment
25318	010031	UNION- E TEXAS PLT DEHYD	R	2,000	00	100	SU
48536	010609	APACHE - SE PASS DEHYD	R	1,000	01	500	SU
30053	010706	MOBIL-E CAMERON BLK 64 DEHYD	R	0	01	800	SU
39808	010710	PATTERSON DEHYDRATION	R	.217	01	500	SU
38778	010729	ZIM DEHYDRATION	R	1,282	00	100	SU
32069	010839	CONOCO-GRAND ISLE BLK 43 DEHYD	R	0	01	500	SU
26713	011037	APACHE - E PLACEDO DEHYD	R	0	00	100	SU
30731	011210	SOUTH MARSH ISLAND 27-A	R	0	01	500	SU
37387	011750	SOUTH MARSH ISLAND 243C	R	0	01	800	SU
27131	011788	KATY TRANSPORT	R	0	00	100	SU
37195	011844	UMC-BRIDGELINE-WEST CAMERON BLK 202	R	0	01	800	SU
45171	011892	EXXON-S T 54 FIELD (55-E)	R	0	01	500	SU
21885	011953	AMERICAN - SEVEN SISTERS TRANSPORT	R	0	00	100	SU
42911	012035	LIBERTY HILL	R	0	01	100	SU
99690	012102	SHIP SHOAL 111-A	R	0	01	500	SU
110072	012112	CHEVRON - EUGENE ISLAND 238-E	R	0	01	500	SU
142126	012328	JOHNSON BAYOU	R	4,460	01	800	SU
162197	012358	SOUTH PASS BLK 55 DEHYD DUAL (420002	R	9,000	01	500	SU
31405	018022	EUGENE ISLAND 331	R	795	01	500	SU
29949	018027	WEST CAMERON 643B	R	0	01	800	SU
32130	020741	STATION 47 POOLING POINT	R	0	01	100	SU
32118	020743	STATON 834 POOLING POINT	R	0	01	800	SU
32125	020744	STATION 542 POOLING POINT	R	0	01	500	SU
110184	020785	STATION 32 POOLING POINT	R	0	00	100	SU
123772	020795	SOUTH WEBSTER	D	0	04	200	SU
153932	020800	SOUTH WEBSTER #2	D	18,754	03	087	SU

Receipt
TGP Meter

Service Package: 820
Contract MDQ: 30725
Flow Date/Time: 07/02/1999 09:00
Requested Date/Time: 07/02/1999 11:12

Leg 100: 10754
Leg 500: 13519
Leg 800: 6452

Location Code	Meter Number	Meter Name	Meter Purpose	Meter Quantity	Meter Zone	Meter Leg	Meter Segment
23268	010004	DALEN - LOS INDIOS DEHYD	R	0	00	100	SU
25031	010008	UNION- WARDNER COASTAL PLT DEHYD	R	0	00	100	SU
25318	010031	UNION- E TEXAS PLT DEHYD	R	1,154	00	100	SU
38535	010144	SHELL - SHERIDAN PLANT DEHYD	R	1,052	00	100	SU
40866	010173	VALERO-SUN PLANT DEHYD	R	4,000	00	100	SU
30953	010527	EUGENE ISLAND DEHYDRATION	R	1,188	01	500	SU
41846	010570	TRANSCO - SECOND BAYOU DEHYD	R	0	01	800	SU
48536	010609	APACHE - SE PASS DEHYD	R	2,800	01	500	SU
32090	010665	EXXON-W DELTA BLK 30 DEHYD	R	0	01	500	SU
37464	010672	SOUTH PASS BLOCK 24 2 DEHYDRATION H	R	0	01	500	SU
10571	010698	ORYX-LAKE PELTO DEHYD	R	600	01	500	SU
38778	010729	ZIM DEHYDRATION	R	702	00	100	SU
71142	011291	LOUISIANA-CLEAR LAKE DEHYD	R	1,000	01	100	SU
37099	011966	WILLIAMS - DIXIE RICE #1	R	2,800	01	800	SU
103778	012101	EXXON - WEST CHALKLEY	R	0	01	800	SU
[illegible]0072	012112	CHEVRON - EUGENE ISLAND 238-E	R	0	01	500	SU
[illegible]42126	012328	JOHNSON BAYOU	R	3,117	01	800	SU
162197	012358	SOUTH PASS BLK 55 DEHYD DUAL (420002	R	3,000	01	500	SU
223394	012407	SOUTH PELTO 2	R	1,783	01	500	SU
235520	012494	WARDER COASTAL PLANT DEHYD	R	2,846	00	100	SU
31405	018022	EUGENE ISLAND 331	R	4,148	01	500	SU
27551	018055	VERMILION 221	R	535	01	800	SU
28401	020044	BROAD RUN CORNWELL (Bi 1-1879)	D	30,725	03	087	SU
19291	060012	ELLISBURG INJECTION (CNG) Bi 7-0012	D	0	04	300	S2

APPENDIX Q

PRESENTATION MATERIALS

Rochester Gas And Electric

GAS SUPPLY RFP
Pre-Bid Meeting

Houston 1/18/00

AGENDA

- Introductions
- Purpose and Objectives
- Background
  - Company
  - State's restructuring of gas industry
  - RG&E gas supply
- Review of RFP Contents
- Responses to Written Questions
- Milestone Schedule
- Q & A

Purpose and Objectives

- Achieve city gate cost reductions
  - substantial
  - permanent
  - manage price volatility
- Address PSC's concerns regarding RG&E's capacity costs
- Manage transition through deregulation
- Comply with PSC competitive restructuring program

BACKGROUND

- Company:
  - Customers 285,000
  - Gas Business Revenues $279 Million
  - System Throughput 53 BCF (normalized for weather)
  - Retail Load 32 BCF (normalized for weather)
  - System Peak Day 500 Mdt
  - Retail Peak Day 365 Mdt

PSC Competitive Gas Restructuring

- LDCs should exit the merchant function
- Hold capacity contracts to a minimum
- Minimize stranded costs
- Freeze/reduce rates to customers
- Maintain reliability
- Facilitate migration/retail access

Where are we today?

A. Description of Portfolio

- Listing of assets
- CNG system (Caledonia city gate)
- Empire System (Mendon city gate)

Where are we today?

- **Caledonia Capacity**
  - Summer 115,196 dt/day
  - Winter 277,690 dt/day
- **Mendon Capacity**
  - Annual 172,500 dt/day

Total Capacity

287,696 dt/day

450,190 dt/day

Where are we?

Capacity Contract Expirations

- TGP 10/31/00
- TETCO 10/31/00
- CNGT 03/31/01
- ANR, GLGT,TCPL, Empire 10/31/08

Where are we?

- **Demand costs**
  - RG&E
  - NY State Average
  - RG&E (Potential)

Where are we today?

- Supply Contracts
  - Amoco 10/31/00
  - Engage 10/31/01
- Open Season
  - Simultaneous Process

Where are we today?

- Forecasted Retail Requirements --
  - Mostly Residential Space Heating (See Appendix H)
- Design Day
  - Retail 365,000 dt at 99 Percentile (-7 degrees)
- Annual Retail Load -- 32 BCF
  - Winter 24 average day 159,000 dt/d
  - Summer 8 average day 37,000 dt/d

Where are we today?

- **City Gate Constraints**
  - The need to balance Mendon and Caledonia
  - Appendix D shows model
  - Temperature sensitive within seasons
  - Suppliers must comply with constraints

- **Balancing**
  - Imbalances automatically go to CNG No-Notice Storage

Where are we going?

B. Service required [redacted]

- Full requirements Firm supply
  - 1-5 suppliers
  - Contract MDQs>=50,000 dt/day
  - Term 1 year or greater (Longer term preferred)
  - Contract MDQ adjusted for migration by RG&E
  - No new capacity contracts by RG&E (except for balancing assets)
  - Suppliers assigned pro rata share of assets

Where are we going?

B. Service required and terms of service:

- Full requirements Firm supply
  - Suppliers assigned pro rata share of daily imbalances and no-notice storage assets
  - Adhere to city gate constraints
  - Forecasting of daily loads by RG&E
  - Suppliers nominate and schedule gas -- ensure reliable delivery
  - Load requirements subject to migration

Where are we going?

- **Capacity Contracts**
  - Assignment
  - Changes
  - PSC requirements

Where are we going?

How Would Balancing Work (pg. 37)

- Daily - RG&E forecasts retail requirements
- Suppliers will be allocated 60,000 dt/d of FTNN for RG&E system imbalances
- 95% of time imbalances +/- 40,000 dt/d
- Suppliers nominate gas
  - Determine flowing and +/- storage
  - Mendon nominations flow to gate
  - Any system imbalance hits Caledonia gate
- Imbalances settle on CNGT FTNN or similar service
- Imbalances allocated to each supplier pro rata

Where are we going?

Future storage system balancing options

- New services may be available in future to address system balancing
- For example, DPO/CSC service
- Each supplier will have their own no-notice account
- Supplier will have pro rata share of injection rights and withdrawal rights

Where are we going?

- **Storage Inventory**
  - RG&E will assign
- **Pricing**
  - NYMEX FOM 3-day average plus numeric premium and demand charges
  - Refer to bid response form (Appendix I)

Where are we going?

C Form of Contract

Penalties for Failure to Deliver

- Peak days -- higher than replacement costs
- Non-peak days -- replacement costs and related charges

Where are we going?

Force Majeure

- Since RG&E will not hold capacity in market area
- Force Majeure will be limited to downstream pipelines
- Supplier will be obligated to use best efforts to avoid force majeure impact and mitigate

- **Termination of contract**
- **Liability**

How are we going to get there?

D. Term of Contract

- Start May 1, 2000
- Prefer longer term bids

E. Contents of Proposal

- Six copies of proposal
- Due by 5 PM EST, February 3, 2000 (follow instructions)
- Financials
- Credit Worthiness
- Supplier Qualification Questionnaire
- Responsive proposals plus alternates
- Confidentiality

How are we going to get there?

F. Preliminary analysis and contract negotiation

- **Evaluate proposals based on--**
  - Reliability of Service
  - Low city gate prices
  - Low demand prices
  - Demonstrated ability and experience to perform
  - Proposal responsiveness
  - Longer term preferable

How are we going to get there?

Time Line

- Capacity open season bids due — 1/21/00 **
- RFP Supply bids due — 2/03/00
  - Identify and release "obvious" capacity deals **
  - Perform RFP Evaluation Process
  - Update proposals if needed
  - Identify short list — 2/25/00
- Commence negotiations — 2/28/00
- Select Supplier(s) and effectuate contract(s) — 5/01/00

** Open season on capacity

Conclusions and Summary

- **National Marketers are better positioned to optimize assets values through**
  - Market diversity
  - Trading diversity
  - Products diversity
  - Contracting leverage with pipelines
  - Contracting leverage with suppliers

- **RG&E looks forward to your bid responses!**

APPENDIX D

REVENUE REQUIREMENT EXHIBITS

ROCHESTER GAS AND ELECTRIC CORPORATION
Gas Department
Income Statement & Rate of Return
Revenue Requirement Projection
(000's)

INCLUDING RATE RELIEF

	Test Yr End Dec 31, 1999	Adjust- ments		Pro Forma Dec 31, 1999	Adjust- ments		Rate Year Jun 30, 2001	Adjust- ments		Rate Year Jun 30, 2002
REVENUES										
CUSTOMER	276,747	10,081	a	286,828	(22,947)	d	263,881	(9,820)		254,061
OTHER REVENUES	1,912	0		1,912	123	e	2,035	0		2,035
REVENUE INCREMENT	0	0		0	14,165	f	14,165	4,021		18,186
TOTAL REVENUES	278,659	10,081		288,740	(8,659)		280,081	(5,799)		274,282
LESS: PURCHASED GAS	146,985	5,316	b	152,301	(18,277)	g	134,024	(9,412)		124,612
LESS: REVENUE TAXES	13,386	487	c	13,873	(2,336)	h	11,537	(243)		11,294
NET REVENUES	118,288	4,278		122,566	11,954		134,520	3,856	I	138,376
EXPENSES	63,824	(4,685)		59,139	3,625		62,764	1,897		64,661
AMORTIZATION	220	283		503	(357)		146	(503)		(357)
DEPRECIATION	12,548	0		12,548	1,001		13,549	1,300		14,849
TAXES-LOCAL,STATE,OTHER	13,754	277		14,031	574		14,605	339		14,944
OP. INCOME BEFORE F.I.T.	27,942	8,403		36,345	7,111		43,456	823		44,279
FEDERAL INCOME TAX PROVISION	8,581	1,907		10,488	2,086		12,574	132		12,706
BALANCE FOR RETURN	19,361	6,496		25,857	5,025		30,882	691		31,573
AVERAGE RATE BASE	297,813	14,746		312,559	23,160		335,719	8,870		344,589
RATE OF RETURN	0.06501			0.08273			0.09199			0.09163
RETURN ON EQUITY	5.90%			9.74%			11.75%			11.75%

ROCHESTER GAS AND ELECTRIC CORPORATION
Gas Department
Income Statement & Rate of Return
Revenue Requirement Projection
(000's)

RATE RELIEF DETAI

	Test Yr End Dec 31, 1999	Adjust-ments	Pro Forma Dec 31, 1999	Adjust-ments	Rate Year Jun 30, 2001	Adjust-ments	Rate Year Jun 30, 2002
REVENUES							
CUSTOMER	0	0	0	0	0	0	0
OTHER REVENUES	0	0	0	0	0	0	0
REVENUE INCREMENT	0	0	0	14,165	14,165	4,021	18,186
TOTAL REVENUES	0	0	0	14,165	14,165	4,021	18,186
LESS: PURCHASED GAS	0	0	0	0	0	0	0
LESS: REVENUE TAXES	0	0	0	579	579	165	744
NET REVENUES	0	0	0	13,586	13,586	3,856	17,442
EXPENSES	0	0	0	286	286	81	367
AMORTIZATION	0	0	0	0	0	0	0
DEPRECIATION	0	0	0	0	0	0	0
TAXES-LOCAL,STATE,OTHER	0	0	0	0	0	0	0
OP. INCOME BEFORE F.I.T.	0	0	0	13,300	13,300	3,775	17,075
FEDERAL INCOME TAX PROVISION	0	0	0	4,655	4,655	1,321	5,976
BALANCE FOR RETURN	0	0	0	8,645	8,645	2,454	11,099
AVERAGE RATE BASE	297,813	14,746	312,559	23,160	335,719	8,870	344,589
RATE OF RETURN INCREMENT	0.02698		0.00926		0.02575		0.03221
Revenue Increment / Customer Revenu	0.00%		0.00%		5.37%		1.79%
Cumulative Revenue Incr / Cust Revenu	0.00%		0.00%		5.37%		7.16%

* at current rates

Rochester Gas and Electric Corporation
Gas Department
Expenses
Revenue Requirement Projection
(000's)

Escal

YEAR ENDING>>>	Dec 31, 1999	Adjust-ments		Dec 31, 1999	Adjust-ments		Jun 30, 2001	Adjust-ments		Jun 30, 2002
Operation & Maint Expenses										
Payroll	26,770	812	a	27,582	1,709	j	29,291	609		29,900
Benefits	6,649	(1,450)	b	5,199	242	k	5,441	109		5,550
Materials & Supplies	852	820	c	1,672	(7)		1,665	39		1,704
Vouchers - Outside Services	7,670	(668)	d	7,002	493	l	7,495	183		7,678
Vouchers - Legal	1,095	0		1,095	(131)	m	964	24		988
Vouchers - Other	11,075	(514)	e	10,561	340	n	10,901	274		11,175
Telephone	617	(153)	f	464	63	o	527	13		540
Postage	805	0		805	(31)	p	774	18		792
Uncollectibles	7,777	(2,008)	g	5,769	0		5,769	0		5,769
Pension Credit	(2,973)	(349)	h	(3,322)	(209)	q	(3,531)	477		(3,054)
Other	3,487	(1,175)	i	2,312	870	r	3,182	70		3,252
Total O&M Expenses	63,824	(4,685)		59,139	3,339		62,478	1,816	s	64,294
Purchased Gas Cost	146,985	5,316		152,301	(18,277)		134,024	(9,412)		124,612
Gas Cost Deferral	0	0		0	0		0	0		0
Purchased Gas Cost, Net	146,985	5,316		152,301	(18,277)		134,024	(9,412)		124,612

Rochester Gas and Electric Corporation
Gas Department
Amortizations and Book Depreciation
Revenue Requirement Projection
(000's)

YEAR ENDING>>>	Dec 31, 1999	Adjust-ments		Dec 31, 1999	Adjust-ments		Jun 30, 2001	Adjust-ments		Jun 30, 2002
Amortization Items:										
Contractor Settlement	0	0		0	(357)	*e*	(357)	0		(357)
Jefferson Road	(178)	178	*a*	0	0		0	0		0
FASB 112 Post Employment	496	7	*b*	503	0		503	(503)	*f*	0
CIS Plus	(301)	301	*c*	0	0		0	0		0
Y2K	203	(203)	*d*	0	0		0	0		0
Total Amortizations	220	283		503	(357)		146	(503)		(357)
Book Depreciation	12,548	0		12,548	1,001	*g*	13,549	1,300	*h*	14,849

Rochester Gas and Electric Corporation
Gas Department
Taxes, Other Than Income
Revenue Requirement Projection

(000's)

YEAR ENDING>>>	Dec 31, 1999	Adjust-ments		Dec 31, 1999	Adjust-ments		Jun 30, 2001	Adjust-ments		Jun 30, 2002
Property Taxes	10,766	0		10,766	386	*b*	11,152	268		11,420
Payroll Taxes	2,118	277	*a*	2,395	0		2,395	47		2,442
Sales & Use Tax	600	0		600	66	*c*	666	16		682
Sales & Use Tax, Audits	(158)	0		(158)	189	*d*	31	1		32
Excess Dividends Tax	301	0		301	(10)		291	6		297
Other Taxes	127	0		127	(57)	*e*	70	1		71
Total excl Rev Taxes	13,754	277		14,031	574		14,605	339	*f*	14,944
Revenue Taxes	13,386	487		13,873	(2,915)		10,958	(408)		10,550

Rochester Gas and Electric Corporation
Gas Department
Federal Income Tax
Revenue Requirement Projection

(000's)

YEAR ENDING>>>	Dec 31, 1999	Adjust-ments		Dec 31, 1999	Adjust-ments		Jun 30, 2001	Adjust-ments		Jun 30, 2002
Operating Income Before F.I.T.	27942	8,403		36345	(6,189)		30156	(2,952)		27204
Interest Expense	(11,039)	681	a	(10,358)	(490)	c	(10,848)	(172)		(11,020)
Additional Deductible Depreciation	(2,111)	0		(2,111)	(12)		(2,123)	(66)		(2,189)
Property Tax Adjustment	1,040	0		1,040	(520)	d	520	(520)		
Cost of Removal	(555)	0		(555)	87	e	(468)	0		(468)
Prior Period Adjustment	3,635	(3,635)	b	0	0		0	0		0
Total	18,912	5,449		24,361	(7,124)		17,237	(3,710)		13,527
FIT at 35%	6,619	1,907		8,526	(2,493)		6,033	(1,299)		4,734
Deferred FIT, Cost of Removal	(199)	0		(199)	100	f	(99)	99		0
Deferred FIT, Accelerated Depreciation	2,161	0		2,161	(176)	g	1,985	11		1,996
Federal Income Tax Provision	8,581	1,907		10,488	(2,569)		7,919	(1,189)	h	6,730

Rochester Gas and Electric Corporation
Gas Department
Average Rate Base
Revenue Requirement Projection
(000's)

YEAR ENDING>>>	Dec 31, 1999	Adjust-ments	Dec 31, 1999	Adjust-ments	Jun 30, 2001	Adjust-ments	Jun 30, 2002
Net Plant	319,822	0	319,822	21,252 i	341,074	14,192	355,266
Working Capital:							
Materials & Supplies	1,714	0	1,714	0	1,714	0	1,714
Gas Storage	15,900	0	15,900	(358) j	15,542	(5,876)	9,666
Prepayments	5,809	0	5,809	0	5,809	0	5,809
Working Capital, EB Cap	8,141	0	8,141	0	8,141	0	8,141
Total Working Capital	31,564	0	31,564	(358)	31,206	(5,876)	25,330
Accumulated Deferred ITC	(3,937)	0	(3,937)	442 k	(3,495)	296	(3,199)
Accumulated Deferred FIT:							
Construction Contributions	997	0	997	37 l	1,034	42	1,076
Unbilled Revenues	2,849	0	2,849	0	2,849	0	2,849
Mortgage Recording Tax	(922)	0	(922)	78 m	(844)	36	(808)
Pensions	236	4,792 a	5,028	(2,429) n	2,599	(1,105)	1,494
Cost of Removal	(1,275)	0	(1,275)	267 o	(1,008)	1	(1,007)
Accelerated Depreciation	(27,831)	0	(27,831)	(2,755) p	(30,586)	(1,954)	(32,540)
Bad Debts	4,324	0	4,324	0	4,324	0	4,324
Gas Inventory Charges	3,880	0	3,880	39	3,919	0	3,919
Post Employment Benefits	3,957	(181) b	3,776	0	3,776	0	3,776
Gas Cost Adjustment	(10,682)	10,682 c	0	0	0	0	0
Other Deferred FIT	437	0	437	0	437	0	437
Amortization Items	243	294 d	537	191 q	728	(44)	684
Total Accum Defd FIT	(23,787)	15,587	(8,200)	(4,572)	(12,772)	(3,024)	(15,796)
Amortization Items:							
Gas Cost Adjustment	5,622	(5,622) e	0	0	0	0	0
Post Employment Benefits	(10,788)	0	(10,788)	0	(10,788)	0	(10,788)
Accrued Pensions	(14,367)	0	(14,367)	6,942 r	(7,425)	3,156	(4,269)
Jefferson Road	(45)	45 f	0	0	0	0	0
FASB 112	(821)	0	(821)	(724) s	(1,545)	(231)	(1,776)
Contractor Settlement	(381)	(333) g	(714)	178 t	(536)	357	(179)
Y2K	553	(553) h	0	0	0	0	0
Total Amortization Items	(25,849)	(841)	(26,690)	6,396	(20,294)	3,282	(17,012)
Total Rate Base	297,813	14,746	312,559	23,160	335,719	8,870 u	344,589

ROCHESTER GAS AND ELECTRIC CORPORATION
Gas Department
Explanation of Adjustments - Normalization & Rate Year
12 Months Ended 12/31/99, 6/30/01 and 6/30/02

Adjustment Letter	$ Gas	Description
Revenues		
a	10,081	Customer Revenues - Weather normalization adjustment made to base period revenues
b	5,316	Purchased Gas - To reflect the effect of weather normalization
c	487	Revenue Taxes - Tracking of change in customer revenues
d	(22,947)	Customer Revenues - Reflects migration, load, fuel cost and revenue tax decreases
e	13	Other Revenues - Increase of reconnect charges
	110	Other Revenues - Eliminate prior period adjustment and supplier refund credits
f	14,165	Revenue Increment - Incremental revenue increase to achieve targeted rate of return of 11.75%
g	(18,277)	Purchased Gas - Reduction due to migration and the cost of gas
h	(2,336)	Revenue Taxes - Tracking of change in cust. revenues and decrease in GRT rate effective 1/1/00
I	3,856	Net Revenues - Net effect of migration and incremental rate increase for RY#2
Operation & Maintenance		
a	122	Payroll - Normalize the months of January & February 1999 to include 3% general increase
	332	Payroll -Dept. 78 incorrectly charged electric payroll in base period - should have been gas payroll
	358	Payroll - Dept. 80 incorrectly charged electric payroll in base period - should have been gas payroll
b	(1,450)	Benefits-Normalize to correct the gas allocation of Flex Benefits overstated in the base period
c	820	An allocation correction to the base period to bring M&S up to normal level. Reversing entry to "other"
d	(651)	VOS - Remove non-recurring Y2K charges
	(17)	VOS - Remove non-recurring BEIR charges
e	(273)	VOT - Remove non-recurring Y2K charges
	(61)	VOT - Remove non-recurring BEIR charges
	(180)	VOT - Correction of charges for organizational dues mis-allocated in the base period
f	(153)	Telephone -To correct bp for misallocation of tele. chgs. that should have been charged to electric
g	(2,008)	Uncollectibles - To lower uncollectibles based on a 3 year historic average
h	(349)	Pension Credit - to correct Base Period amount
I	(353)	Other - Remove non-recurring Y2K charges
	(2)	Other - Remove non-recurring BEIR charges
	(820)	Other - Charges to M&S due to miscategorization in the base period
j	1,255	Payroll - Merit, promotional and general increases with a Productivity adjustment of 1%
	454	Payroll - Increased complement - including field inspectors, construction and maintenance,
		field customer service, gas dispatcher, job schedulers
k	242	Benefits-Co's increased monthly contribution to base flex and medical credits along with Co. match
		of 50% of 401k based on 6% employee contribution versus the original 5%. Productivity adjustment
		to all benefits @ 1%
l	493	VOS - Reflect impact to outsource collection activities and support for CWIP & Gen. ledger projects
m	(131)	Legal - Reduction attributable to an increased emphasis in the electric side for NMP I&II acquisitions
n	340	VOT - Reflect impact of corporate projects
o	63	Telephone - Adjustment to match forecast activity level
p	(31)	Postage - Adjustment to match forecast activity level
q	(209)	Pension Credit - Projected rate year credit
r	365	Other - Increase in travel expenses in rate year due to increase in regulatory activity and departmental
		cross training activities between gas and electric operations which requires seminar trainings
	505	Other - Increase in vehicle depreciation and other misc. adjustments
s	1,816	Escalation factor added to RY#1 cost categories
Amortizations		
a	178	Jefferson Road - fully amortized
b	7	FASB 112
c	301	CIS PLUS - fully amortized
d	(203)	Y2K Project - fully amortized
e	(357)	Contractor Settlement - to reflect passback
f	(503)	FASB 112 - fully amortized
g	1,001	Book Depreciation-to reflect the impact of proposed accrual rates
h	1,300	Book Depreciation-to reflect the impact of proposed accrual rates

ROCHESTER GAS AND ELECTRIC CORPORATION
Gas Department
Explanation of Adjustments - Normalization & Rate Year
12 Months Ended 12/31/99, 6/30/01 and 6/30/02

Adjustment Letter	$ Gas	Description
Taxes - Local, State and Other		
a	277	Payroll Taxes - To match payroll distribution
b	386	Property Taxes - To reflect year 2000 forecast with escalation
c	66	Sales & Use Tax - To reflect year 2000 forecast with escalation
d	189	Sales & Use Tax, Audits - To reflect year 2000 forecast with escalation
e	(57)	Other Taxes - To reflect year 2000 forecast with escalation
f	339	Escalation factor added to RY#1 cost categories
Federal Income Taxes		
a	681	To proform interest deduction
b	(3,635)	To remove prior period adjustment
c	(490)	Interest Expense - To properly allocate interest charges
d	(520)	Property Tax Adjustment - To reflect termination of property tax adjustment
e	87	Cost of Removal - To align with projected rate years
f	100	To reflect forecasted levels of activity
g	(176)	To reflect forecasted levels of activity
h	(1,189)	To reflect forecasted Rate Year levels of activity
Rate Base		
a	4,792	Pensions - To align Deferred F.I.T. with rate base
b	(181)	OPEB'S - To align Deferred F.I.T. with rate base
c	10,682	Gas Cost Adjustment - To align Deferred F.I.T. with rate base
d	294	Amortization Items - To reflect normlization of amortization items
e	(5,622)	To normalize out the Gas Cost Adjustment
f	45	Jefferson Road - fully amortized
g	(333)	Contractor Settlement- To reflect end of period amount
h	(553)	Y2K Project - fully amortized
i	21,252	Net Plant - To reflect Capital forecast and Depreciation forecast
j	(358)	Working Capital - Gas Storage - Actual and forecast injections and withdrawals
k	442	Accum. Deferred ITC - Actual and forecast reinstatements
l	37	Construction Contributions - to align with projected rate year level
m	78	Mortgage Recording Tax - to align with projected rate year level
n	(2,429)	Pensions - to align with projected rate year level
o	267	Cost of Removal - to align with projected rate year level
p	(2,755)	Accelerated Depreciation - to align with projected rate year level
q	191	Amortization items - To reflect deferred F.I.T. offset
r	6,942	Accrued Pensions - To reflect amortization
s	(724)	FASB 112 - To reflect projected amortization
t	178	Contractor Settlement- To reflect projected amortization
u	8,870	To reflect forecasted levels of activity

APPENDIX E

REPORT ON THE DETERMINATION OF THE COST OF COMMON EQUITY

CASE 98-G-1589

In the Matter of Rochester Gas and Electric Corporation's Plans for Gas Rates and Restructuring

REPORT

ON

THE DETERMINATION OF THE COST OF COMMON EQUITY

Robert Rosenberg
Benrose Economic Consultants, Inc.

January 2000

TABLE OF CONTENTS

	Page
INTRODUCTION	1
USE OF A PROXY GROUP	1
DCF ANALYSIS	2
CAPM ANALYSIS	7
RISK PREMIUM ANALYSIS	12
COMPARABLE EARNINGS ANALYSIS	16
DETERMINATION OF THE COST OF EQUITY	20

APPENDICES A AND B

SCHEDULES 1-3

WORKPAPERS

INTRODUCTION

The purpose of this report is to determine the cost of common equity of Rochester Gas and Electric Corporation (hereinafter referred to as RG&E). My qualifications are included in Appendix A to this report.

I will employ four separate approaches to estimate the cost of equity including: (1) a discounted cash flow (DCF) analysis; (2) a capital asset pricing model (CAPM) analysis; (3) two risk premium analyses; and (4) a comparable earnings analysis. While it was always good financial practice to employ several methods to estimate the cost of equity in order to reduce measurement error associated with any particular methodology, that notion has special relevance today. The assessment of utility risk and potential performance is in flux currently due to the uncertainties associated with regulatory restructuring and competitive developments. Therefore, when we attempt to estimate the cost of equity for a particular utility, this uncertainty is likely to lead to more estimation error than under circumstances where that company's more easily forecasted fundamentals are the prime determinant of its stock prices and where that company's risk seems clearly delineated to investors. Under current conditions, my use of four equity costing methods leads to a broader-based set of estimates and will prevent any spurious results from biasing the cost of equity determination.

USE OF A PROXY GROUP

A group of comparison companies was used to estimate the cost of equity for RG&E. Companies were selected for the proxy group if they were electric or combination utilities with data available in Value Line and were rated in the A bond rating category by both Moody's (A1, A2 or A3) and Standard & Poor's (A+, A or A-). (RG&E has an A3/A- bond rating currently.) For holding companies, each and every subsidiary had to meet the above criteria in order to be eligible for selection. Furthermore, companies were excluded if they are involved in any major merger activity currently or consummated such a merger in the recent past. Companies were also excluded if they had significant unregulated operations. Finally, Potomac Electric was excluded because of an apparent dividend reduction being forecast by Value Line. The list of companies in the proxy group is shown on Schedule 1. RGS Energy, the parent company of RG&E, is part of the proxy group.

DCF ANALYSIS

To apply the DCF method, needed elements include the price that investors are paying for a stock in the marketplace and a reliable estimate of the growth expectations that led investors to bid the observed price. Analysts ascertain long-term expected growth by estimating constant expected growth (if the future is expected to be relatively stable) or multiple stages of growth (if there is an expectation that growth may change in the future). It is my opinion that the DCF method is more prone to measurement error currently due to a lack of congruence between the market price and the growth estimate employed due to a lessening of the clarity of investor growth expectations. Many companies in the industry are in flux currently, transitioning to a restructured environment where the final rules have not yet been carved in stone.

Typically, investment analysts provide 5-year growth projections for the companies they cover and investors often employ these projections as their expected growth in the future. However, given the changes occurring in the industry, it is my opinion that these 5-year projections are not good proxies for the long-term expected growth for utilities at the current time. Over the next five years, many utilities are absorbing non-recurring restructuring costs, accelerated depreciation, employee buyouts, etc., which would tend to depress earnings growth below what investors might reasonably expect for the long run. Certain utilities have been assuming a more conservative payout policy either due to the need for more internally generated cash flow or to help deal with the higher risk of earnings fluctuations.

Many utilities have substantial near-term cash flow due to factors such as the curtailment of construction programs, the sale of generation assets or the receipt of securitization proceeds. Numerous utility managements are using this near-term cash flow to buy back common stock. This near-term phenomenon of stock buybacks creates a short-term demand for the stock which raises stock prices above what they would have been, absent the buyback plan.[1]

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1 This is simply because, in a rising market, the fact that a company, itself, is buying back stock, merely adds to the buying pressure already in effect from a buoyant market. If investors think that stock prices might decline, the fact that the company is likely to be a large-scale buyer in a weak market would certainly provide investors with a cushion. Given both of these effects, stock buybacks would raise the price of a utility's stock above what it would be otherwise. Stock buyback plans often are implemented over a number of years. Thus any accretion in growth resulting from the buyback will be expected to be phased in gradually over time.

Investors are also aware that numerous mergers have occurred in the utility industry and more are likely to occur in the near future. The potential for additional mergers could influence investor expectations in three ways. First, mergers have generally occurred at a premium above the pre-merger-announcement market price, leading to capital gains for investors. Second, several mergers have resulted in increases in the dividend received by investors. Third, investors may see mergers as a win-win situation—offering both rate reductions to ratepayers and enhanced return prospects for stockholders. For example, Value Line noted in its March 12, 1999 edition that with mergers "...managers expect better future earnings growth and improved returns for investors." To the extent that there is speculation about future merger activity among utilities, such influence would be reflected in the price, but not in the growth projections made by analysts. The effect on the DCF of such speculation would be to bias the cost of equity estimate downward.

Therefore, due to the complex set of phenomena currently affecting utility stock prices, it is my opinion that a DCF estimate will have more measurement error than DCF calculations performed in the past under more stable circumstances where investor expectations were determined with more certainty. As established in the discussion above, several of the potential sources of DCF measurement error (affecting both the price and expected growth) could lead to a substantial understatement of the cost of equity in a DCF context. Given the potentially large estimation error associated with a DCF calculation currently, I believe it is important to consider the results of the other methods that I present, which approach the determination of the return on equity from different perspectives.

The use of the constant-growth DCF formulation (D/P + g) for a regulated utility often may have been a reasonable assumption in the past when the financial and regulatory environment in which regulated utilities operated was more stable than currently. However, the utility industry currently is in a state of flux, with certain near-term events depressing growth below what investors might expect for the long run. In light of this, I will employ a two-stage DCF calculation to estimate the cost of equity of the comparison companies.

In the DCF analysis, I will employ a pricing period encompassing the six months ending November 1999. On Schedule 2, I show the average prices for the comparison companies over the 6-month period ending November 1999. Each month's price was calculated by averaging the monthly high and low prices. The six-month average price is also shown in Column (1) of Schedule 3 which provides the inputs to the DCF calculation. The indicated dividend level (i.e., the latest quarterly dividend payment multiplied by four) for each of the comparison companies shown in Column (2) of Schedule 3.

I believe that it is reasonable to hypothesize that investors expect growth to be somewhat depressed by industry changes over the short run with higher growth to be experienced over the longer term. Thus, it seems reasonable to employ a two-stage growth formulation of the DCF method under current conditions. For the determination of near-term (i.e., first-stage) growth, I rely on an average of earnings projections made by the Institutional Brokerage Estimate System (IBES). These projections for the comparison companies are shown in Column (3) of Schedule 3.

The estimation of second-stage, long-term growth is more problematic. I am not aware of any projections that are made by financial analysts for this timeframe. However, FERC, in several recent cases, has adopted a conceptual framework employing the long-term projected nominal GDP (Gross Domestic Product) growth as a proxy for expected long-term second-stage growth for an individual company.

The Energy Information Administration (EIA) of the Department of Energy published the Annual Energy Outlook 1999 which contains data that can be used to derive a long-term projection of growth in nominal GDP. Since the near-term growth projections discussed above are for a five-year period, in general, the projection of second-stage long-term growth should start in the year 2004. Using data from the Annual Energy Outlook 1999, I have calculated projected growth GDP for the period 2004-2020 to be 5.26 percent.

I will now summarize the components of the DCF analysis. Columns (1) and (2) of Schedule 3 show the six-month average price and the indicated dividend for the comparison companies. Column (3) shows the IBES projected 5-year growth rates. Column (4) shows the long-term projected growth in GDP, which is assumed to occur after the 5-year first-stage growth period. Column (5) of Schedule 3 shows the DCF cost of equity estimate for each company calculated by an iterative process employing the internal rate of return. (For calculational purposes, I continue the second-stage growth for 200 years because any growth after that point has a negligible effect on any present value or internal rate of return calculation.)

As shown in Column (5) of Schedule 3, the average and median of the DCF results were close to 10.6 percent. Some of the estimates in the lower half of the DCF cost of equity range are either close to or below the 250 basis point risk premium level which was employed for low-end sensitivity testing purposes in the financial integrity portion of the generic proceeding in New York a few years ago. In addition, because interest rates are at relatively low levels now, the risk premium analysis discussed later in my testimony suggests that risk premiums, if anything, should be above their recent historic average level at this point in time. Given these considerations, on Schedule 3, I also report the average and median of the upper half of the range of DCF estimates for the comparison companies. The average and median of the upper half of the sample are close to 11.0 percent. Thus, I will employ a range of 10.6-11.0 percent as the results of my DCF cost of equity calculations for the comparison companies. Based on my discussion, above, concerning the measurement difficulties associated with the application of the DCF method currently, it is my opinion that these results are likely biased downward and should only be considered in conjunction with the results of the other methods I employ.

CAPM ANALYSIS

Under CAPM theory, the formula which can be used to determine the market-required rate of return for a company is:

$$R_i = R_f + b_i\,[E(RP)]$$

where: R_i = required return on security i

R_f = current return on risk-free investments

b_i = beta for security i

E(RP) = expected market risk premium, i.e., the expected difference between the return in the market and the rate of return on a risk-free investment

In the above formulation, the required rate of return for a company is equal to the current return on a risk-free investment plus the product of that company's beta times the expected market risk premium. The market risk premium is that extra return that investors require for an investment in assets of the market as a whole as compared to the return on a risk-free investment. Thus, three parameters must be estimated for the CAPM approach—beta, the current risk-free rate and the expected market risk premium.

The average beta of the comparison companies is 0.54, per The Value Line Investment Survey. I will employ a beta of 0.54 in the CAPM calculation.

Since we are trying to determine the cost of common equity capital for the comparison companies and equity capital is a long-term investment, it is my belief that the yield on long-term government bonds best reflects the risk-free rate in this context. The average yield on 30-year Treasury bonds over the June-November 1999 period was about 6.1 percent. Recent Treasury bond futures yields have been at about the 6.6 percent level. Based on the above-discussed data, I believe it would be appropriate to use a risk-free rate in the range of 6.1-6.6 percent in the CAPM calculation.

For the third parameter needed for the CAPM approach, we must estimate the expected market risk premium—i.e., the expected difference between the market-required return on common stocks and the yield on long-term government bonds. Expectational risk premium data are not directly observable in the marketplace. It is, therefore, necessary to use estimates of historic realized return spreads as proxies for expected risk premiums. Ibbotson Associates publishes the Stocks, Bonds, Bills and

Inflation—1999 Yearbook in which the returns on common stocks and long-term government bonds are reported for the 1926-1998 period. These return data represent the experience of a large number of companies over a lengthy period of time and indicate what return spreads investors have actually achieved, on average, in the past. It is not unreasonable to assume that, given the very extensive return spread experience examined, that investors would use this historic experience in formulating their expected risk premium for the future. Put simply, they see what return spread has been achieved in the past and use that experience as an expectation of what might be achieved in the future. Because of this consideration, I believe that the average historic return spread is appropriate to use as the expected risk premium in a CAPM analysis. Based on the Ibbotson data, the spread between common stock returns and returns on long-term government bonds has been 8.0 percentage points on an historical basis. I will use this 8.0 percent figure as the expected market risk premium in my CAPM analysis.

In the above discussion, I have employed figures reflecting the arithmetic mean rather than the geometric mean of the data. I believe that a rational investor would employ the arithmetic mean and would not use the geometric mean, because that would provide an understatement of expected future return. Since the explanation of why the arithmetic mean should be used is quite lengthy, I have included it in Appendix B. Appendix B shows that the arithmetic mean is the appropriate figure to use when investors are making forecasts about the future and dealing with uncertainties inherent in making projections. A simple example also shows that the arithmetic mean is the correct approach to use in this context. Let us assume that you are faced with the prospect of betting on a coin toss where you win 50 percent of your bet if the coin comes up heads, but lose 50 percent of the bet if the coin comes up tails.[2] Common sense indicates that because the coin is a fair coin (i.e., a 50 percent chance of landing on heads and a 50 percent chance of landing on tails), the bettor would expect to only break even (i.e., they would expect to lose 50 percent of their bet half the time and expect to win 50 percent of their bet half the time). The arithmetic average of the return prospects a bettor would face in these circumstances is zero. Thus, the common sense expectation of a bettor in this example reflects the arithmetic average of return possibilities. In sharp contrast, the geometric average of an equal prospect of two returns (one plus 50 percent and one minus 50 percent) is -13.4 percent. A rational bettor would not go into a coin toss of the type described above with the expectation of a loss of 13.4 percent over time—they would expect to break even, as reflected in the arithmetic mean of zero. Clearly, they would not use a geometric average of return possibilities as their expected value, but would, instead, use the arithmetic average. As further support for my position, I note that the source that I use for the return spread data—the Ibbotson 1999 Yearbook—states that the arithmetic mean is the correct measure to use in estimating the cost of equity capital.

I now move on to implementation of the CAPM approach. The beta for the comparison companies, per Value Line, is 0.54. The expected market risk premium is 8.0 percent. The risk-free rate is in the range of 6.1-6.6 percent. Using these inputs, the average required return for the comparison companies is calculated below:

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2 Implicit in this discussion is an assumption that the coin used is fair—it is not biased (e.g., weighted) to land disproportionately on either heads or tails.

Using a risk-free rate of 6.1 percent

$$R_i = 6.1 + 0.54(8.0) = 10.4\%$$

Using a risk-free rate of 6.6 percent

$$R_i = 6.6 + 0.54(8.0) = 10.9\%$$

Thus, using the Ibbotson risk premium in the CAPM method, I find that the average cost of equity for the comparison companies is in the range of 10.4-10.9 percent.

There is another factor to consider that may not be captured by the CAPM calculations described above. The Ibbotson Associates Stocks, Bonds, Bills and Inflation—1999 Yearbook indicates that companies with market capitalization in the mid- or small-capitalization range (including many utilities) require higher returns than indicated by the CAPM formulation I have employed above. As a way to account for this phenomenon, a size premium can be added to the CAPM results. According to the Ibbotson 1999 Yearbook, size premia of 50 and 110 basis points are appropriate for mid- and low-capitalization companies, respectively. Two of the comparison companies fall in the Ibbotson low-cap range and one falls in the mid-cap range. I will therefore add a 45 basis point size premium to the prior CAPM results. Thus, the CAPM cost of equity range is 10.4-10.9 percent not including a size premium and 10.85-11.35 percent including a size premium.

RISK PREMIUM ANALYSIS

In order to be induced to choose a higher risk investment, an investor would have to be offered an expectation of some increment in return—a premium for incurring additional risk. This incremental return is often known as the "risk premium" and it reflects the additional return that investors require to invest in common equity rather than debt. The cost of equity is not directly observable, but must be estimated using inferences and judgment. In contrast, a bond yield is observable and if we know, or can estimate, the risk premium that common equity investors require to invest in common equity rather than debt, we can employ the risk premium approach to estimate the cost of common equity.

I employ two risk premium approaches. The first analysis is based on the historic average spread between utility stocks and bonds. The second relies on a regression analysis to measure how utility risk premiums vary with the level of interest rates.

In my first analysis, to measure the expected risk premium between utility common stock and utility bonds, I use the average return spread actually achieved by investors in these instruments in the past. Between 1932 and 1998, Moody's electric utility common stock index achieved a market return of 10.76 percent, on average. (The market return in any given year was calculated by summing the dividend paid during that year and the year-end market price and dividing that sum by the beginning-of-year market price.) Over that same period, the average of Moody's composite bond yields for electric utilities was 6.58 percent. Thus, the historically achieved spread between electric utility stock returns and electric utility bond yields was 4.18 percent (10.76 -

6.58 = 4.18). If we add this average spread to the recent level of bond yields, we can obtain an estimate of the return on utility common stocks that investors are currently expecting/requiring. Over the six-month period ending November 1999, the average of Moody's A bond yields was 7.88 percent. Adding this recent average bond yield to the historic average spread between electric utility common stock returns and electric utility bond yields of 4.18 percent, we obtain a cost of equity estimate for the proxy group of 12.06 percent.

In my second risk premium analysis, I use returns on common equity allowed to electric utilities by regulation as a proxy for required returns on equity. Most regulatory commissions, frequently refer to movements in, or the level of, interest rates in their decisions establishing an allowed return on equity. Since authorized returns appear to be interest-rate sensitive, employing allowed returns from across the United States in calculating the risk premium serves to use outside, objective evidence as to what the consensus of regulation believes is the spread between the cost of equity and bond yields.

To implement this second approach, I conducted an analysis of risk premiums implied by allowed returns on equity since 1980. Specifically, quarterly average allowed returns for the first quarter 1980 through the third quarter 1999 were obtained from data in Regulatory Research Associates Regulatory Focus. These data reflect the average of allowed returns for all electric utility cases decided in the quarter specified. An implied risk premium (which can also be thought of as an allowed return spread) was derived by comparing the average allowed return in a given quarter with the average yield for Moody's Utility Composite Bond Index in the two quarters prior to the average allowed return.

In deriving the implied risk premium, the utility bond yields were lagged behind the allowed returns on equity because of the likelihood that changes in allowed returns on equity often lag somewhat behind changes in bond yields. This could be so for two reasons—one economic and one practical. The economic reason is that commissions might want to be convinced that a change in interest rates actually represented a trend that might persist before reflecting such change in the allowed return on equity. The practical reason simply deals with the logistics of a rate case—the record that a commission examines may be several months old by the time it renders a decision. (While certain commissions update record data in their decisions, many commissions do not do so.) Furthermore, the simple logistics of writing a decision may cause a delay between the period upon which the allowed return was based and the date on which the decision was released to the public.

To determine the sensitivity of the implied risk premiums described above to the level of interest rates, a regression analysis was conducted. In this regression, the implied risk premium described above was the dependent variable and the level of interest rates, as proxied by the yield on long-term Treasury bonds lagged two quarters behind the allowed return on equity, was the independent variable. This model attempts to capture the statistical relationship between implied risk premiums (i.e., allowed returns minus utility bond yields) and the level of interest rates (as indicated by the yields on 30-year Treasury bonds), with the interest rates being lagged two quarters behind the allowed return on equity. The regression equation is reported below:

$$\text{Risk Premium} \quad = \quad 7.208 - 0.502 \begin{Bmatrix} \textit{Yield on } 30-\textit{Year} \\ \textit{Treasury} \\ \textit{Bonds} \end{Bmatrix}$$

The adjusted R^2 of the regression (which measures the proportion of variation in the dependent variable explained by variation in the independent variable) is 0.85. Thus, this regression relationship demonstrates that changes in the level of interest rates explain a substantial proportion of the changes in implied risk premiums.

One might well ask why one should go through the process of creating the model described above when one could merely just examine recent levels of allowed returns. There are justifications for the model in this context. First, it is possible that in certain quarters there are an insufficient number of allowed returns to use as a guide by themselves. Second, allowed returns are not a perfect proxy for required returns and the use of the long-term relationship between allowed returns and bond yields allows us to overcome any unusual allowed return results in a particular period.

The average yield on 30-year Treasury bonds for the six months ending November 1999 is 6.10 percent. Inserting this into the model shown above, I obtain a calculated risk premium of 4.15 percent as follows:

$$\text{Risk Premium} \quad = \quad 7.208 \ - \ 0.502(6.10)$$
$$\text{Risk Premium} \quad = \quad 4.15\%$$

The average yield on Moody's A-rated bonds in the six months ending November 1999 was 7.88 percent. Adding the A yield of 7.88 percent to the risk premium derived above of 4.15 percent produces an implied cost of equity for A utilities of 12.03 percent.

Thus, my second risk premium cost of equity estimate for the proxy group of utilities is 12.03 percent according to the above-described analysis.

I will now summarize the two risk premium analyses. The first risk premium approach that employs the historic average spread between utility common stock returns and utility bond yields produced a cost of equity estimate for the proxy group of 12.06 percent. The second risk premium approach which was based on a regression analysis measuring how utility risk premiums change as the level of interest rates change produced a cost of equity estimate of 12.03 percent for the proxy group.

COMPARABLE EARNINGS ANALYSIS

In the Bluefield and Hope decisions, the Supreme Court enumerated a two-part standard for a fair rate of return: (1) a fair rate of return to a regulated company is one that is equal to that earned in other enterprises of similar risk and (2) the fair rate of return must also provide enough earnings to enable the company to maintain its credit standing and to attract capital. The first part has come to be known as the "comparable earnings standard" while the second part is referred to as "the capital attraction standard." The comparable earnings approach (i.e., determining the return earned by companies of similar risk) directly meets one of the basic criteria set forth by the Supreme Court in the Bluefield and Hope decisions.

In addition to being prescribed as a standard by the Bluefield and Hope decisions, there are other reasons why a comparable earnings analysis may be helpful in determining the return to be allowed a regulated company. The comparable earnings method analyzes the question of what return should be allowed a regulated company from a different perspective than an approach such as the DCF method. It can be argued that the price that investors pay in the stock market for a utility depends, at least in part, on the return that investors expect a commission will allow that company. In turn, however, the return that a commission will allow a company depends, at least in part, on the price of that company in the stock market. As one commentator has stated:

> Moreover, since the most important risk to the investor is the risk as to the attitude of the regulatory commission, current security prices inevitably reflect projections not only of future physical and general economic developments of the utility and its area, but also of the anticipated rulings of the commission. For the commission to "rely" on such anticipations is palpably circular reasoning.... Commissions and investors cannot sensibly continue to look behind one another like endless images in multiple mirror.[3]

Thus there is an element of circularity in using an approach such as the DCF method to estimate the cost of equity of a utility. The comparable earnings method, which derives its results from a conceptually different approach, can shed additional light on the question of the appropriate allowed return for a utility.

Under the comparable earnings approach, I first evaluate the risk of the comparison companies versus that of companies in the U.S. economy in general using the Value Line Safety Rank and based on this analysis determine what return on equity is appropriate. The Value Line Investment Survey provides a safety rank for the 1700 or so companies that it follows. Value Line defines the Safety Rank as a measure of the total risk of a stock and describes the Safety Rank as one of the main criteria investors

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3 Harold Leventhal, "Vitality of the Comparable Earnings Standard for Regulation of Utilities in a Growth Economy," The Yale Law Journal, May 1965, page 1007.

should consider in selecting stocks. Value Line derives the Safety Rank by averaging two variables: (1) the volatility of the stock as measured by its Index of Price Stability and (2) the Financial Strength Rating as determined by Value Line analysts. Value Line defines the price stability index as being based upon a ranking of the standard deviation of weekly percent changes in price of a stock over the last five years. Value Line evaluates the Financial Strength of a company on a scale of A++ down to C. This is a relative ranking comparing the subject company's financial strength to all other companies. The rating is based upon financial leverage, business risk, company size and the judgment of Value Line analysts. The analysts examine various ratios such as coverage, return variability, accounting methods and size.

For the determination of Safety Rank, stocks are ranked from 1 to 5, with 1 being the safest and 5 being the most risky. The median Safety Rank for the comparison group is 2. To implement the comparable earnings analysis, I examined recent earned and projected returns on shareholders' equity earned by companies with a safety factor of 2 as reported in The Value Line Investment Survey.

The earned return on shareholders' equity in any one given year is not necessarily the return that investors expect a firm to earn in the future. A company could have runs of good luck or bad luck or particular accounting adjustments so that the return earned in any one year is not necessarily a meaningful indicator of what it ought to be earning in light of the risks being borne. In order to temper the earned return data, I examined earned returns on shareholders' equity over several recent historic years. These historic data help smooth economic fluctuations, but are not from so long ago as to be ancient history. In addition, Value Line projected earned returns for the current year (2000) and for a period 3-5 years into the future were also employed. Thus, by looking at both the earnings experience of the recent past as well as projections for the future, unusual figures are smoothed and the end result is appropriate to employ as the comparable earnings result. To further temper the data, median results, rather than average figures, were used in any year.

The median returns on shareholders' equity in 1997 and 1998 for companies accorded by Value Line a safety factor of 2 are 14.6 in both years, while the return in 1999 was 14.5 percent. The median projected return on shareholders' equity for these companies in 2000 is 15.0 percent. The median return for these companies projected by Value Line for the near-term future (2002-2004) is 15.5 percent.

In summary, a conservative estimate[4] of the return to be allowed on common equity using the comparable earnings approach is in the range of about 14.5-15.5 percent.

DETERMINATION OF THE COST OF EQUITY

I will review the results of the four equity costing methods I employ. The comparable earnings approach (i.e., determining the return earned by companies of similar risk) directly meets one of the basic criteria set forth by the Supreme Court in the Bluefield and Hope decisions. As utilities face a more competitive environment,

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[4] The data that I examined reflect the return earned on shareholders' equity, rather than the return on common equity. Since the companies examined are financed in part by some preferred equity in addition to common equity, the returns on common equity would be higher than those reported. In addition, Value Line reports return on year-end shareholders' equity, whereas it is appropriate to use return on average equity for the comparable earnings analysis.

investors will carefully evaluate how utility returns compare to those of unregulated enterprises. The comparable earnings analysis produced a return on equity range of 14.5-15.5 percent. These expected returns on equity of comparable-risk investment alternatives would certainly be taken into account by investors in forming their return requirements for a utility. As discussed above, it is difficult to ascertain with clarity at the current time what the prospects of the utility industry will be in the future. However, the use of rates of return of companies of comparable risk across a diversity of industries provides a very important benchmark as to the return to be allowed in this proceeding.

The CAPM approach can be thought of as calculating a risk premium for the market as a whole and then adjusting it for the risk of the particular electric utility in question. Under the CAPM approach, risk is measured by a company's beta.[5] My CAPM analysis produced cost of equity estimates in the range of 10.85-11.35 percent reflecting a size premium and 10.4-10.9 ?? not including a size premium.

While the CAPM approach calculates a market-wide risk premium which is then adjusted for company-specific risk, the two risk premium analyses that I performed directly estimate the risk premium for an electric utility. The results of these risk premium analyses produced a cost of equity figure of about 12.05 percent.

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5 I note that work in the generic proceeding suggested that the measured beta for companies with beta less than 1.0 (including most utilities) understates the true risk/required return position of such companies.

The fourth method for which I performed calculations is the DCF method. The DCF analysis I conducted produced a cost of equity estimate in the range of 10.6-11.0 percent. As I indicated in my testimony, given that stock prices currently are being affected by a complex set of phenomena, including a changing assessment of utility risk, I believe that a utility DCF estimate will have more measurement error (and potential downward bias) than during periods in which a company's more-readily-determined future earnings and dividends prospects were the main consideration. Given the potentially large estimation error associated with a DCF calculation for utilities currently, I believe that it is important to consider the results of the other methods that I presented, which approach the determination of the return on equity to be allowed in this proceeding from different perspectives.

The results of my analyses are summarized in tabular form below:

Cost of Equity Method		Range	
DCF		10.6 - 11.0	%
CAPM			
Excluding Size Premium		10.4 - 10.9	
Including Size Premium		10.85 - 11.35	
Risk Premium		12.03 - 12.06	
Comparable Earnings		14.5 - 15.5	

Determination of the cost of equity requires inferences regarding investor expectations and requirements, which are not directly observable. Each of the above-described methods approaches the estimation of the cost of equity from a different perspective—which I believe to be a strength of this four-method approach. In my opinion, the cost of equity of the comparison companies is in the range of 11.5-12.0 percent. This range is toward the center of results shown above which reflect the broad-base approach I used to estimate the cost of equity of the comparison companies. In my opinion, an allowed return in the range of 11.5-12.0 percent would give RG&E an opportunity to maintain its financial health and to attract capital on reasonable terms when necessary.

EDUCATION AND EMPLOYMENT BACKGROUND OF ROBERT ROSENBERG

Education

I have a Bachelor of Arts degree in Political Science, with a minor in Economics, from Hunter College. I received a Master of Business Administration degree with a major in Finance at the New York University Graduate School of Business Administration.

Employment

From 1969 through mid-March 1983, I was employed by the firm of National Economic Research Associates (NERA), reaching the position of Senior Economic Analyst. In March of 1983, I became a principal of Benrose Economic Consultants, Inc., a consulting firm in New York City. Benrose Economic Consultants performs economic research and consulting services for companies, law firms, government agencies and trade associations. Throughout this period, I have concentrated on the analysis of regulated industries, including electric and gas utilities, insurance and steamship companies. I have prepared direct and rebuttal testimony related to financial aspects of utility rate proceedings—e.g., cost of common equity, capital structure, etc. Along with these "typical" rate case issues, I have also testified regarding more unusual matters: intra-company royalty payments; the correct procedure to use in calculating the cost of debt; whether a cogeneration project met Qualifying Facility ownership standards; and responsibility for stranded costs.

I have had numerous assignments involving evaluation, consultation and/or internal reports to clients. Examples of this include: (1) analyzing issues relating to industry restructuring (e.g., implications of Commission-ordered divestiture, the risks associated with the institution of incentive plans, unbundling electric rates, etc.); (2) consulting with a utility company concerning the financial and regulatory aspects of a potential merger and the possible regulatory treatment of an acquisition premium; (3) evaluating the feasibility of instituting an administrative securitization proposal; (4) determining incremental risks flowing from purchased power contracts; and (5) analyzing studies regarding property values near transmission lines.

Outside the regulatory arena, I have estimated financial damages related to (1) breach of contract and (2) earnings losses as a result of injuries. I have also examined stock prices to see if alleged manipulation was likely and have performed economic valuation for employee stock option plan purposes.

I have presented lectures at the Pace University Center for International Business Studies regarding the regulatory process. Five articles that I authored have been published in Public Utilities Fortnightly (PUF).

Appearances Before Regulatory Agencies

I have presented testimony before the Federal Energy Regulatory Commission and the regulatory agencies in the following states: Kentucky, Massachusetts, Minnesota, Mississippi, New Hampshire, New York, Rhode Island and South Dakota. These testimonies were presented on behalf of: Blackstone Valley Electric Company, Boston Edison Company, Central Hudson Gas & Electric Corporation, Consolidated Edison Company, Kentucky Utilities Company, Long Island Lighting Company, Louisville Gas & Electric Company, Minnesota Power & Light Company, Mississippi Power Company, Niagara Mohawk Power Corporation, Northern States Power, Orange & Rockland Utilities, Pacific Gas & Electric Company, Public Service Company of New Hampshire, Public Service Company of New Mexico and Rochester Gas & Electric Corporation. In addition, I have testified before: the Society of Maritime Arbitrators concerning the estimation of damages in the matter of Empresa Publica de Abastecimento de Cereais (an agency of the Government of Portugal) vs. Point Endeavor Corporation and Tradigrain, Inc.; U.S. Bankruptcy Court regarding financing for an office building in Chapter 11; and the Federal Maritime Commission regarding the fair return for Matson Navigation Company.

WHY THE ARITHMETIC, RATHER THAN THE GEOMETRIC, MEAN SHOULD BE USED IN ESTIMATING EXPECTED FUTURE RETURNS

It has been suggested that in using the Ibbotson historic rate of return data as a proxy for the expected future return, one should employ the geometric mean of the data, rather than the arithmetic mean. I will demonstrate why that contention is incorrect. The only appropriate historic average to use in forecasting expected returns for the future is the arithmetic mean. It is incorrect to use the geometric mean and the use of the geometric mean results in an understated expected future return, as will be demonstrated below.

Before beginning the discussion on this issue, it is perhaps helpful to review the basic definition of the return on an investment that an investor expects (requires). The expected (required) rate of return is the discount rate that equates the future cash flows that an investor expects to receive from an investment with the initial value (i.e., the present value) of that investment. Keeping that basic definition in mind, I will now explain why the arithmetic mean of historic return data is appropriate to use in trying to forecast the expected return in the future.

In examining complicated issues, economists often simplify the actual very complex data or situation of the real world so that the issue in question is more easily examined in the simplified context. I will do so in my discussion below, but note that the principles hold even in the more complex situation of the real world. Let us assume that over a past period, an investment earned a rate of return of either 15 percent or 5 percent, with equal probability. Thus, if we examined an historic period of, say, 100 years, we would expect to find that 50 of those years experienced a 15 percent return, while the remaining 50 years experienced a 5 percent return. Since the two possible returns in this simplified hypothetical example have the same probability, the arithmetic average of these two possible returns would be 10 percent. Having established that the arithmetic average of past returns for the series described is 10 percent, we will now examine whether it is appropriate to use that return as a proxy for expected future returns.

On Attachment 1, I show a hypothetical example of future possible investment outcomes if we assume that the distribution of possible returns from the past continues on into the future—i.e., that the only two possible returns are 15 percent or 5 percent, each with a 50 percent probability. In Column (1) of Attachment 1, I show the two possible returns that can be expected to occur in the future, given that these were the only two returns that occurred in the past in our hypothetical example. In Column (2) of Attachment 1, I show that the initial amount invested is assumed to be $1.00. In Column (3) I show that at the end of Year 1 an investor could either end up with $1.15 if the 15 percent return outcome happens or $1.05 if the 5 percent return possibility happens. Since the $1.15 outcome and the $1.05 outcome are equally likely to happen under the hypothesized circumstances, the average possible result (known in financial parlance as the expected value) of this investment at the end of Year 1 is $1.10—the average of the two possible outcomes that have equal probability. This expected value of the investment of $1.10 is shown near the bottom of Column (3) of Attachment 1. If the expected value of this investment at the end of Year 1 is $1.10 and $1.00 had been invested in Year 0, then clearly the discount factor that equates the expected cash flow at the end of Year 1, should the security be sold, to the value of the initial investment is 1.10 or 10 percent.

Now let us see what are the possible investment outcomes for Year 2 under the hypothesized circumstances. The possible outcomes are shown in Column (4) of Attachment 1 and are explained below. If the investment earns \$1.15 in Year 1 and again, fortunately, earns a 15 percent return in Year 2, then the value of the investment would be \$1.3225 at the end of Year 2 (\$1.15 x 1.15 = \$1.3225). Another possible outcome would be if the investment earns \$1.15 in Year 1 but only earns a 5 percent return in Year 2. This would produce a value at the end of Year 2 of \$1.2075 (\$1.15 x 1.05 = \$1.2075). I will now explain how the third number in Column (4) is derived. If the investment in question earns a 5 percent return in Year 1, but then earns a 15 percent return in Year 2, then the expected value of the investment at the end of Year 2 would be \$1.2075 (\$1.05 x 1.15 = \$1.2075). The fourth possibility in Year 2 is if the investment, unfortunately, only reaches the \$1.05 level at the end of Year 1 and in Year 2 again only experiences a 5 percent return. This would produce the fourth outcome in Column (4), namely \$1.1025 (\$1.05 x 1.05 = \$1.1025).

I have thus explained how one obtains the four possible outcomes at the end of Year 2, as shown in Column (4) of Attachment 1. Given that each of these outcomes has the same probability (because in any given year there is an equal probability of experiencing either a 15 percent return, or a 5 percent return), if we add up the four possible returns and divide by 4, we obtain the expected value of the investment of \$1.21. Thus, even though there are several possible outcomes in Year 2, the expected value of this investment at the end of Year 2 is \$1.21 under the circumstances hypothesized. If the investor expects to be able to sell the investment at the end of Year 2 with a value of $1.21, then the discount rate that equates the expected receipt of $1.21 at the end of Year 2 with the initial investment of $1.00 in Year 0 is 10 percent ($\$1.21/[(1.10)^2]=\$1.00$). Thus, again, as in Year 1, in Year 2 we find that the discount rate, or expected return, on this investment is 10 percent. This means that if an investor invested $1.00 in Year 0 and expected the return possibilities shown on Attachment 1, that the investor would expect to earn a 10 percent return on his or her investment in either Year 1 or in Year 2.

The data shown for Years 3 and 4, in Columns (5) and (6) on Attachment 1, are derived in a similar manner. I will briefly discuss the data for Year 3 to provide continuity for this explanation. There are eight possible outcomes in Year 3, each with the same probability. Thus, if we sum up the eight possible investment outcomes for Year 3 and divide by 8, we have the average possible outcome or the expected value of the investment at the end of Year 3. As shown in Column (5) on Attachment 1, the expected value of the investment at the end of Year 3 is $1.331. Thus, if an investor invested $1.00 in Year 0 and could expect to sell his investment at the end of Year 3 for $1.331, the expected return on that investment would be 10 percent. The data shown for Year 4, in Column (6) of Attachment 1, are derived in a similar manner and again it is indicated that were the investor to sell his investment at the end of Year 4, he would expect to earn a 10 percent return on the investment. This hypothetical example could be extended out further in time, but the calculations would obviously become very cumbersome. The point holds for future years, but the data for Years 1 through 4 will be used for illustrative purposes in the remainder of this discussion.

The hypothetical example shown on Attachment 1 has demonstrated that under the hypothesized circumstances, in each and every year in the future, investors will expect to earn a return of 10 percent. It is important to note that this 10 percent return that we have calculated that investors could expect in each of the years examined is the same return as the arithmetic average of the two possible return outcomes specified in the hypothetical example, namely 15 percent and 5 percent. Thus, if investors noted that historic return experience was either 5 or 15 percent, with an arithmetic average of 10 percent, and they used this arithmetic average of past returns as a projected return for the future, their projections would exactly match the expected return (or discount rate), derived in the hypothetical example on Attachment 1. Put simply, this demonstrates that the arithmetic average of past rates of return is the appropriate average to use in forecasting expected future returns, assuming that past conditions will continue on into the future.

Now let us leave the discussion of the arithmetic mean briefly in order to discuss the geometric mean. The geometric mean of two returns is calculated as follows:

$$\sqrt{(1 + r_1) \times (1 + r_2)} - 1$$

where r_1 and r_2 are the two returns in question and are expressed in decimal form.

Given that in the prior hypothetical example the only two possible returns were 15 percent or 5 percent, the geometric average of those returns would be calculated as follows:

$$\sqrt{(1+.15) \times (1+.05)} - 1 = .0989 \text{ or } 9.89\%$$

As can be noted above, the geometric mean rate of return for the hypothetical investment we have been discussing is 9.89 percent—less than the 10.00 percent arithmetic mean. From the calculations on Attachment 1, we have shown that if an investor invested $1.00 at Year 0 in our hypothetical investment, they could expect to have the following values of their investment for each of the years specified:

Initial nvestment in Year 0	Expected Value of Investment			
	Year 1	Year 2	Year 3	Year 4
$1.00	$1.10	$1.21	$1.331	$1.4641

As noted previously, these expected values of the investment in each year could also be obtained by taking the arithmetic average of historic results (10 percent) and assuming that the investor expects to earn the arithmetic return in each year in the future.

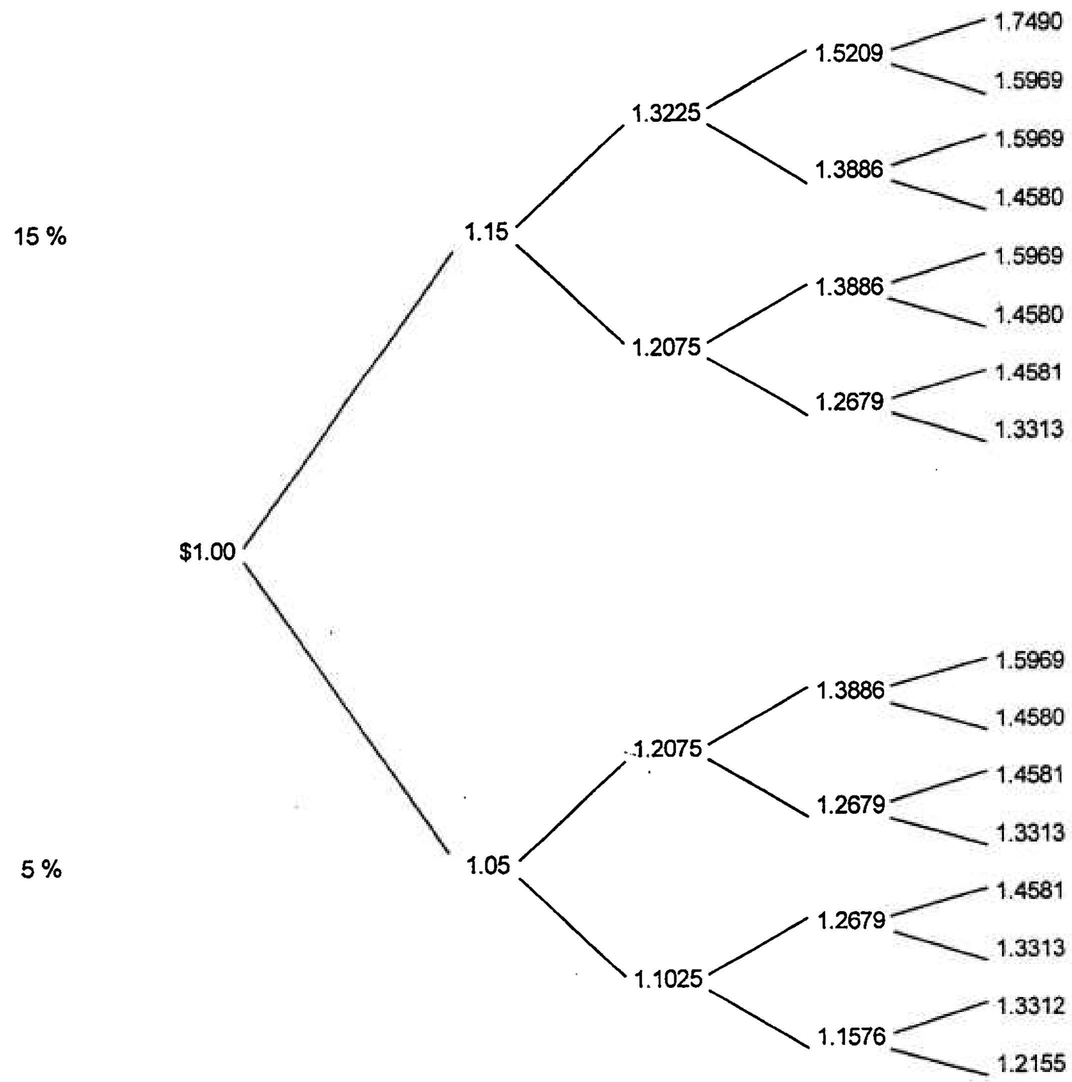
Now let us assume that an investor mistakenly took the 9.89 percent geometric mean from the historic return series and used that to project the returns earned in the future. If an investor invested $1.00 in Year 0 and expected that he or she would only earn the 9.89 percent geometric mean, then using the geometric mean as a predictor would produce the following data:

Initial nvestment in Year 0	Value Produced by Forecasting with Geometric Mean			
	Year 1	Year 2	Year 3	Year 4
$1.00	1.0989	1.2076	1.3270	$1.4582

Note that the values produced above when one uses the geometric mean to forecast future investment outcomes are lower in each and every year than the actual expected value of the investment that was derived on Attachment 1. This means that the geometric mean will produce an understated prediction of the returns that investors expect in the future. As has been demonstrated throughout this discussion, the arithmetic mean of historic rate of return data produces the rate of return that investors expect in the future, assuming that future conditions parallel that of the past. In contrast, use of the geometric mean to forecast future rates of return based on past results will result in an understatement of the forecasted rate of return for the future.

HYPOTHETICAL EXAMPLE OF FUTURE POSSIBLE INVESTMENT OUTCOMES

Possible Rate of Return	Initial Investment in Year 0	Future Possible Investment Outcome In: Year 1	Year 2	Year 3	Year 4
	-----	-----	----- Dollars -----	-----	-----
(1)	(2)	(3)	(4)	(5)	(6)



Expected Value of Investment		$1.10	$1.2100	$1.3310	$1.4641
Discount Factor		1.10	$(1.10)^2$	$(1.10)^3$	$(1.10)^4$

PROXY GROUP
A/A ELECTRIC AND COMBINATION UTILITIES

Allegheny Energy

Central Hudson G&E

Cleco

DTE

P. S. Enterprise

RGS Energy (RGE)

CALCULATION OF SIX-MONTH AVERAGE PRICE

June - November 1999

	Average of Monthly High and Low Price					
	June	July	August	September	October	November
	(1)	(2)	(3)	(4)	(5)	(6)
Allegheny Energy	$33.53	$33.38	$34.09	$32.62	$31.75	$29.81
Central Hudson G&E	41.81	41.72	42.38	40.94	38.69	35.44
Cleco	31.69	31.47	32.25	32.81	32.56	33.53
DTE	42.34	40.47	39.19	37.53	34.38	33.38
P. S. Enterprise	41.34	40.91	41.00	39.47	38.62	36.56
RGS Energy (RGE)	27.50	26.69	25.59	25.06	24.62	23.62

Source: Standard & Poor's "Stock Guide," various issues.

DCF COST OF EQUITY CALCULATION

	6-Month Average Price (1)	Indicated Dividend (2)	IBES Projected 5-Year Growth (3)	Projected Growth in GDP (4)	DCF Cost of Equity Estimate (5)
Allegheny Energy	$32.53	$1.72	4.0 %	5.24 %	10.51 %
Central Hudson G&E	40.16	2.16	1.0	5.24	9.93
Cleco	32.39	1.66	4.0	5.24	10.35
DTE	37.88	2.06	5.0	5.24	10.90
P. S. Enterprise	39.65	2.16	4.0	5.24	10.67
RGS Energy (RGE)	25.51	1.80	2.0	5.24	11.70
Entire Sample					
Average					10.68 %
Median					10.59 %
Upper Half of Sample					
Average					11.09 %
Median					10.90 %

Source:	Cols. (1)&(2)	--	Standard & Poor's Stock Guide.
	Col. (3)	--	Institutional Brokers Estimate System (IBES), Monthly Summary Data.
	Col. (4)	--	Derived from data in Energy Information Administration Annual Energy Outlook, 1999.
	Col. (5)	--	Derived by iteration using an internal rate of return calculation.

APPENDIX F

CUSTOMER BILL IMPACTS

Example of RG&E Service Classifcation No. 1 Bill with Rollout of Gas Costs from Base Rates:

Current Structure of RG&E Gas Bill:

Cost of Gas Used		
Local Distribution Costs		
Minimum Monthly Charge up to 3 Thms	+	6.90
Next 97 Therms @ $0.62488/ Therm	+	60.61
Next 27 Therms @ $0.61016/ Therm	+	16.47
Gas Cost Adj 127 Therms @ $0.06318/ Therm	+	8.02
Gross Revenue Surcharge @7.5269% x $92.00	+	6.92
Total Gas Cost for 127 THM Used at $0.778898	$	98.92

Proposed Bill Structure, with Rollout of Gas Costs:

Local Distribution Costs		
Minimum Monthly Charge up to 3 Thms	+	5.81
Next 97 Therms @ $0.26026 / Therm	+	25.25
Next 27 Therms @ $0.24554 / Therm	+	6.63
Gas Costs		
Gas Costs 127 Therms @ $0.42776/ Therm	+	54.33
Gross Revenue Surcharge @ 7.5269% x $92.00	+	6.92
Total Gas Cost for 127 THM Used at $0.778898	$	98.92

The proposed bill structure reflects the rollout of gas costs ($0.358 cents per therm, plus losses), from each level of local distribution costs. This gas cost is now included with the Gas Cost Adjustment charge, and renamed 'Gas Costs' in the proposed bill structure.

Case No. 98-G-1589

Rochester Gas and Electric Corporation
Gas Department
12 Months Ending June 30, 2001
Rate Changes Resulting from Increase in Minimum Charge and Rollout of Base Cost of Gas from SC#1 Rates

		PRESENT		PROPOSED	
SC#1 RATE TABLE					
0	3	$6.90000	$0.00000	$7.91000	$0.00000
4	100	$5.02536	$0.62488	$7.19664	$0.23779
101	500	$6.49736	$0.61016	$8.54155	$0.22434
501	1,000	$18.30736	$0.58654	$19.33191	$0.20276
1,001	30,000	$145.57736	$0.45927	$127.44220	$0.09465
30,001	100,000	$735.07736	$0.43962		
100,001	1,000,000	$5,335.07736	$0.39362		
SC#5 RATE TABLE					
0	3	$5.81000	$0.00000	$7.91000	$0.00000
4	100	$5.02922	$0.26026	$7.19664	$0.23779
101	500	$6.50122	$0.24554	$8.54155	$0.22434
501	1,000	$18.31122	$0.22192	$19.33191	$0.20276
1,001	30,000	$145.58122	$0.09465	$127.44220	$0.09465
30,001	100,000	$735.08122	$0.07500		
100,001	1,000,000	$5,335.08122	$0.02900		
SC#3 RATE TABLE					
0	1,000	$240.00000	$0.00000	$222.00000	$0.00000
1,001	30,000	$145.35000	$0.09465	$127.35000	$0.09465
30,001	100,000	$734.85000	$0.07500	$716.85000	$0.07500
100,001	1,000,000	$5,334.85000	$0.02900	$5,316.85000	$0.02900
1,000,001	10,000,000	$19,784.85000	$0.01455	$19,766.85000	$0.01455
SC#3 RATE TABLE HP Option					
0	1,000	$710.00000	$0.00000	$710.00000	$0.00000
1,001	30,000	$681.00000	$0.02900	$681.00000	$0.02900
30,001	100,000	$681.00000	$0.02900	$681.00000	$0.02900
100,001	1,000,000	$681.00000	$0.02900	$681.00000	$0.02900
1,000,001	10,000,000	$15,131.00000	$0.01455	$15,131.00000	$0.01455

BASE COST OF GAS	$0.358
LOSS FACTOR	1.0185
SC#1 GAS COSTS	$0.482041
SC#3 AVERAGE TRA	$0.008489
SC#5 AVERAGE TRA-RG&E	$0.107283
SC#5 AVERAGE TRA-OTHER	$0.027468
MINIMUM GRT RATE	3.3592%
AVERAGE SC#1 GCA	$0.117418
ACTUAL INCREASE	$0
DIFFERENCE	$0
AVERAGE SC#3 BALANCING	$0.007609
SC#5 BALANCING - RG&E	$0.087424
SC#5 BALANCING - OTHER	$0.007609

Case No. 98-G-1589

Rochester Gas and Electric Corporation
Gas Department
12 Months Ending June 30, 2002
Rate Changes Resulting from Increase in Minimum Charge

		PROPOSED RATE YEAR 1		PROPOSED RATE YEAR 2	
SC#1 RATE TABLE					
0	3	$7.91000	$0.00000	$10.00000	$0.00000
4	100	$7.19664	$0.23779	$9.35402	$0.21533
101	500	$8.54155	$0.22434	$10.57190	$0.20315
501	1,000	$19.33191	$0.20276	$20.34311	$0.18361
1,001	1,000,000	$127.44220	$0.09465	$109.30303	$0.09465
SC#5 RATE TABLE					
0	3	$7.91000	$0.00000	$10.00000	$0.00000
4	100	$7.19664	$0.23779	$9.35402	$0.21533
101	500	$8.54155	$0.22434	$10.57190	$0.20315
501	1,000	$19.33191	$0.20276	$20.34311	$0.18361
1,001	1,000,000	$127.44220	$0.09465	$109.30303	$0.09465
SC#3 RATE TABLE					
0	1,000	$222.00000	$0.00000	$204.00000	$0.00000
1,001	30,000	$127.35000	$0.09465	$109.35000	$0.09465
30,001	100,000	$716.85000	$0.07500	$698.85000	$0.07500
100,001	1,000,000	$5,316.85000	$0.02900	$5,298.85000	$0.02900
1,000,001	10,000,000	$19,766.85000	$0.01455	$19,748.85000	$0.01455
SC#3 RATE TABLE HP Option					
0	1,000	$710.00000	$0.00000	$710.00000	$0.00000
1,001	30,000	$681.00000	$0.02900	$681.00000	$0.02900
30,001	100,000	$681.00000	$0.02900	$681.00000	$0.02900
100,001	1,000,000	$681.00000	$0.02900	$681.00000	$0.02900
1,000,001	10,000,000	$15,131.00000	$0.01455	$15,131.00000	$0.01455

BASE COST OF GAS	$0.358
LOSS FACTOR	1.0185
SC#1 GAS COSTS	$0.482041
SC#3 AVERAGE TRA	$0.008489
SC#5 AVERAGE TRA-RG&E	$0.107283
SC#5 AVERAGE TRA-OTHER	$0.027468
MINIMUM GRT RATE	3.3592%
AVERAGE SC#1 GCA	$0.117418
ACTUAL INCREASE	$0
DIFFERENCE	$0
AVERAGE SC#3 BALANCING	$0.007609
SC#5 BALANCING - RG&E	$0.087424
SC#5 BALANCING - OTHER	$0.007609

ROCHESTER GAS AND ELECTRIC CORPORATION

Gas Department

General Service Bill Comparison

Present and Proposed

12 Months Ending June 30, 2001 and June 30, 2002

Service Classification No. 1

	Amount			Summary of Changes: Proposed Rate Year 1 over Present		Proposed Rate Year 2 over Proposed Rate Year 1		Total Gas Customer Count
Therms	Present	Proposed RY1	Proposed RY2	Amount	%	Amount	%	Avg. Winter Bill
3	$7.50	$9.67	$11.83	$2.17	29.0%	$2.16	22.3%	2,066
10	$12.87	$14.88	$16.88	$2.01	15.6%	$2.00	13.4%	2,493
15	$16.70	$18.60	$20.48	$1.90	11.4%	$1.88	10.1%	1,740
20	$20.54	$22.32	$24.08	$1.78	8.7%	$1.77	7.9%	1,978
30	$28.21	$29.76	$31.29	$1.55	5.5%	$1.53	5.2%	3,412
40	$35.88	$37.20	$38.50	$1.32	3.7%	$1.30	3.5%	2,829
50	$43.56	$44.64	$45.71	$1.08	2.5%	$1.07	2.4%	2,605
60	$51.23	$52.08	$52.92	$0.85	1.7%	$0.84	1.6%	2,829
70	$58.90	$59.52	$60.12	$0.62	1.1%	$0.60	1.0%	3,566
80	$66.57	$66.96	$67.33	$0.39	0.6%	$0.37	0.6%	4,328
90	$74.25	$74.40	$74.54	$0.15	0.2%	$0.14	0.2%	5,549
100	$81.92	$81.84	$81.75	($0.08)	-0.1%	($0.09)	-0.1%	7,205
110	$89.44	$89.14	$88.83	($0.30)	-0.3%	($0.31)	-0.3%	9,074
120	$96.96	$96.44	$95.91	($0.52)	-0.5%	($0.53)	-0.5%	11,217
130	$104.48	$103.74	$102.99	($0.74)	-0.7%	($0.75)	-0.7%	13,235
140	$112.00	$111.04	$110.08	($0.95)	-0.9%	($0.97)	-0.9%	14,882
150	$119.52	$118.34	$117.16	($1.17)	-1.0%	($1.19)	-1.0%	16,113
160	$127.04	$125.65	$124.24	($1.39)	-1.1%	($1.41)	-1.1%	16,271
170	$134.56	$132.95	$131.32	($1.61)	-1.2%	($1.62)	-1.2%	16,135
180	$142.08	$140.25	$138.40	($1.83)	-1.3%	($1.84)	-1.3%	15,393
190	$149.60	$147.55	$145.49	($2.05)	-1.4%	($2.06)	-1.4%	13,811
200	$157.12	$154.85	$152.57	($2.27)	-1.4%	($2.28)	-1.5%	12,417
210	$164.64	$162.15	$159.65	($2.49)	-1.5%	($2.50)	-1.5%	10,775
220	$172.16	$169.45	$166.73	($2.71)	-1.6%	($2.72)	-1.6%	9,247
230	$179.68	$176.75	$173.81	($2.93)	-1.6%	($2.94)	-1.7%	7,721
240	$187.20	$184.05	$180.90	($3.15)	-1.7%	($3.16)	-1.7%	6,565
250	$194.72	$191.36	$187.98	($3.36)	-1.7%	($3.38)	-1.8%	5,498
350	$269.92	$264.37	$258.80	($5.56)	-2.1%	($5.57)	-2.1%	24,876
500	$382.73	$373.88	$365.03	($8.84)	-2.3%	($8.85)	-2.4%	7,287
600	$455.49	$444.66	$433.83	($10.82)	-2.4%	($10.83)	-2.4%	1,622
700	$528.25	$515.44	$502.63	($12.80)	-2.4%	($12.81)	-2.5%	982
800	$601.01	$586.22	$571.43	($14.78)	-2.5%	($14.79)	-2.5%	659
900	$673.77	$657.00	$640.23	($16.76)	-2.5%	($16.77)	-2.6%	486
1,000	$746.53	$727.78	$709.03	($18.74)	-2.5%	($18.75)	-2.6%	385
5,000	$3,130.77	$3,112.02	$3,093.28	($18.74)	-0.6%	($18.75)	-0.6%	2,742
10,000	$6,111.07	$6,092.32	$6,073.58	($18.74)	-0.3%	($18.75)	-0.3%	200
20,000	$12,071.67	$12,052.93	$12,034.18	($18.74)	-0.2%	($18.75)	-0.2%	13
30,000	$18,032.27	$18,013.53	$17,994.78	($18.74)	-0.1%	($18.75)	-0.1%	2

Notes: Present bills include current SC#1 base rates, the average SC#1 GCA rate, and the current minimum GRT rate. Proposed Rate Years 1 and 2 bills include proposed base rates, SC#1 gas costs rate, and the current minimum GRT rate.

ROCHESTER GAS AND ELECTRIC CORPORATION
Gas Department
General Service Bill Comparison
Present and Proposed
12 Months Ending June 30, 2001 and June 30, 2002
Service Classification No. 3

	Amount				Summary of Changes: Proposed Rate Year 1 over Present		Proposed Rate Year 2 over Proposed Rate Year 1	
Therms	Present	Proposed RY1	Proposed RY2	Balancing	Amount	%	Amount	%
1,000	$256.84	$238.23	$219.63	$7.61	($18.60)	-7.2%	($18.60)	-7.8%
2,000	$363.44	$344.84	$326.23	$15.22	($18.60)	-5.1%	($18.60)	-5.4%
3,000	$470.04	$451.44	$432.83	$22.83	($18.60)	-4.0%	($18.60)	-4.1%
4,000	$576.65	$558.04	$539.44	$30.44	($18.60)	-3.2%	($18.60)	-3.3%
5,000	$683.25	$664.65	$646.04	$38.05	($18.60)	-2.7%	($18.60)	-2.8%
7,500	$949.76	$931.16	$912.55	$57.07	($18.60)	-2.0%	($18.60)	-2.0%
10,000	$1,216.27	$1,197.66	$1,179.06	$76.09	($18.60)	-1.5%	($18.60)	-1.6%
15,000	$1,749.29	$1,730.68	$1,712.08	$114.14	($18.60)	-1.1%	($18.60)	-1.1%
20,000	$2,282.31	$2,263.70	$2,245.10	$152.18	($18.60)	-0.8%	($18.60)	-0.8%
25,000	$2,815.32	$2,796.72	$2,778.11	$190.23	($18.60)	-0.7%	($18.60)	-0.7%
30,000	$3,348.34	$3,329.74	$3,311.13	$228.27	($18.60)	-0.6%	($18.60)	-0.6%
35,000	$3,779.81	$3,761.21	$3,742.60	$266.32	($18.60)	-0.5%	($18.60)	-0.5%
40,000	$4,211.28	$4,192.67	$4,174.07	$304.36	($18.60)	-0.4%	($18.60)	-0.4%
45,000	$4,642.75	$4,624.14	$4,605.54	$342.41	($18.60)	-0.4%	($18.60)	-0.4%
50,000	$5,074.21	$5,055.61	$5,037.00	$380.45	($18.60)	-0.4%	($18.60)	-0.4%
100,000	$9,388.89	$9,370.29	$9,351.68	$760.90	($18.60)	-0.2%	($18.60)	-0.2%
150,000	$11,326.31	$11,307.70	$11,289.10	$1,141.35	($18.60)	-0.2%	($18.60)	-0.2%
200,000	$13,263.72	$13,245.12	$13,226.52	$1,521.80	($18.60)	-0.1%	($18.60)	-0.1%
250,000	$15,201.14	$15,182.54	$15,163.93	$1,902.25	($18.60)	-0.1%	($18.60)	-0.1%
300,000	$17,138.56	$17,119.95	$17,101.35	$2,282.70	($18.60)	-0.1%	($18.60)	-0.1%
350,000	$19,075.97	$19,057.37	$19,038.76	$2,663.15	($18.60)	-0.1%	($18.60)	-0.1%
400,000	$21,013.39	$20,994.79	$20,976.18	$3,043.60	($18.60)	-0.1%	($18.60)	-0.1%
450,000	$22,950.81	$22,932.20	$22,913.60	$3,424.05	($18.60)	-0.1%	($18.60)	-0.1%
500,000	$24,888.22	$24,869.62	$24,851.01	$3,804.50	($18.60)	-0.1%	($18.60)	-0.1%
750,000	$34,575.31	$34,556.70	$34,538.10	$5,706.75	($18.60)	-0.1%	($18.60)	-0.1%
850,000	$38,450.14	$38,431.53	$38,412.93	$6,467.65	($18.60)	0.0%	($18.60)	0.0%
1,000,000	$44,262.39	$44,243.78	$44,225.18	$7,609.00	($18.60)	0.0%	($18.60)	0.0%

Notes: Present and proposed bills include present and proposed SC#3 base rates, the average SC#3 balancing charge (Level 1), and other rate adjustments applicable to pre-11/96 customers. The balancing amount is only the Level 1 balancing charge.

ROCHESTER GAS AND ELECTRIC CORPORATION
Gas Department
General Service Bill Comparison
Present and Proposed
12 Months Ending June 30, 2001 and June 30, 2002
Service Classification No. 5 without using SC No. 8 Storage Service

	Amount				Summary of Changes: Proposed Rate Year 1 over Present		Proposed Rate Year 2 over Proposed Rate Year 1	
Therms	Present	Proposed RY1	Proposed RY2	Balancing	Amount	%	Amount	%
3	$6.34	$8.51	$10.67	$0.26	$2.17	34.2%	$2.16	25.4%
10	$9.00	$11.01	$13.00	$0.87	$2.01	22.3%	$2.00	18.2%
15	$10.90	$12.79	$14.67	$1.31	$1.89	17.4%	$1.88	14.7%
20	$12.80	$14.57	$16.34	$1.75	$1.78	13.9%	$1.77	12.1%
30	$16.59	$18.14	$19.67	$2.62	$1.54	9.3%	$1.53	8.5%
40	$20.39	$21.70	$23.01	$3.50	$1.31	6.4%	$1.30	6.0%
50	$24.19	$25.27	$26.34	$4.37	$1.08	4.5%	$1.07	4.2%
60	$27.99	$28.84	$29.68	$5.25	$0.85	3.0%	$0.84	2.9%
70	$31.79	$32.40	$33.01	$6.12	$0.61	1.9%	$0.60	1.9%
80	$35.59	$35.97	$36.34	$6.99	$0.38	1.1%	$0.37	1.0%
90	$39.39	$39.54	$39.68	$7.87	$0.15	0.4%	$0.14	0.4%
100	$43.19	$43.10	$43.01	$8.74	($0.08)	-0.2%	($0.09)	-0.2%
110	$46.83	$46.53	$46.22	$9.62	($0.30)	-0.6%	($0.31)	-0.7%
120	$50.48	$49.96	$49.43	$10.49	($0.52)	-1.0%	($0.53)	-1.1%
130	$54.13	$53.39	$52.64	$11.37	($0.74)	-1.4%	($0.75)	-1.4%
140	$57.77	$56.81	$55.85	$12.24	($0.96)	-1.7%	($0.97)	-1.7%
150	$61.42	$60.24	$59.06	$13.11	($1.18)	-1.9%	($1.19)	-2.0%
160	$65.07	$63.67	$62.26	$13.99	($1.40)	-2.1%	($1.41)	-2.2%
170	$68.71	$67.10	$65.47	$14.86	($1.62)	-2.4%	($1.62)	-2.4%
180	$72.36	$70.53	$68.68	$15.74	($1.84)	-2.5%	($1.84)	-2.6%
190	$76.01	$73.95	$71.89	$16.61	($2.05)	-2.7%	($2.06)	-2.8%
200	$79.65	$77.38	$75.10	$17.48	($2.27)	-2.9%	($2.28)	-2.9%
210	$83.30	$80.81	$78.31	$18.36	($2.49)	-3.0%	($2.50)	-3.1%
220	$86.95	$84.24	$81.52	$19.23	($2.71)	-3.1%	($2.72)	-3.2%
230	$90.59	$87.66	$84.72	$20.11	($2.93)	-3.2%	($2.94)	-3.4%
240	$94.24	$91.09	$87.93	$20.98	($3.15)	-3.3%	($3.16)	-3.5%
250	$97.89	$94.52	$91.14	$21.86	($3.37)	-3.4%	($3.38)	-3.6%
350	$134.36	$128.79	$123.23	$30.60	($5.56)	-4.1%	($5.57)	-4.3%
500	$189.06	$180.21	$171.36	$43.71	($8.85)	-4.7%	($8.85)	-4.9%
600	$223.08	$212.25	$201.42	$52.45	($10.83)	-4.9%	($10.83)	-5.1%
700	$257.11	$244.30	$231.49	$61.20	($12.81)	-5.0%	($12.81)	-5.2%
800	$291.14	$276.35	$261.56	$69.94	($14.79)	-5.1%	($14.79)	-5.4%
900	$325.16	$308.39	$291.62	$78.68	($16.77)	-5.2%	($16.77)	-5.4%
1,000	$359.19	$340.44	$321.69	$87.42	($18.75)	-5.2%	($18.75)	-5.5%
5,000	$1,194.05	$1,175.29	$1,156.54	$437.12	($18.76)	-1.6%	($18.75)	-1.6%
10,000	$2,237.63	$2,218.86	$2,200.11	$874.24	($18.78)	-0.8%	($18.75)	-0.8%
20,000	$4,324.80	$4,305.99	$4,287.24	$1,748.48	($18.81)	-0.4%	($18.75)	-0.4%
30,000	$6,411.96	$6,393.12	$6,374.37	$2,622.72	($18.84)	-0.3%	($18.75)	-0.3%

Notes: Present and proposed bills include present and proposed SC#5 base rates, the balancing charge assuming the supplier does not take SC#8 storage service, and other rate adjustments applicable to SC#5 customers. The balancing amount calculates the balancing charge only.

ROCHESTER GAS AND ELECTRIC CORPORATION
Gas Department
General Service Bill Comparison
Present and Proposed
12 Months Ending June 30, 2001 and June 30, 2002
Service Classification No.5 using SC No. 8 Storage Service

	Amount				Summary of Changes: Proposed Rate Year 1 over Present		Proposed Rate Year 2 over Proposed Rate Year 1	
Therms	Present	Proposed RY1	Proposed RY2	Balancing	Amount	%	Amount	%
3	$6.09	$8.26	$10.42	$0.02	$2.17	35.6%	$2.16	26.1%
10	$8.17	$10.18	$12.18	$0.08	$2.01	24.6%	$2.00	19.6%
15	$9.66	$11.55	$13.43	$0.11	$1.89	19.6%	$1.88	16.3%
20	$11.15	$12.92	$14.69	$0.15	$1.78	15.9%	$1.77	13.7%
30	$14.12	$15.66	$17.20	$0.23	$1.54	10.9%	$1.53	9.8%
40	$17.09	$18.41	$19.71	$0.30	$1.31	7.7%	$1.30	7.1%
50	$20.07	$21.15	$22.22	$0.38	$1.08	5.4%	$1.07	5.1%
60	$23.04	$23.89	$24.73	$0.46	$0.85	3.7%	$0.84	3.5%
70	$26.02	$26.63	$27.23	$0.53	$0.61	2.4%	$0.60	2.3%
80	$28.99	$29.37	$29.74	$0.61	$0.38	1.3%	$0.37	1.3%
90	$31.96	$32.11	$32.25	$0.68	$0.15	0.5%	$0.14	0.4%
100	$34.94	$34.85	$34.76	$0.76	($0.08)	-0.2%	($0.09)	-0.3%
110	$37.76	$37.46	$37.15	$0.84	($0.30)	-0.8%	($0.31)	-0.8%
120	$40.58	$40.06	$39.53	$0.91	($0.52)	-1.3%	($0.53)	-1.3%
130	$43.40	$42.66	$41.91	$0.99	($0.74)	-1.7%	($0.75)	-1.8%
140	$46.22	$45.27	$44.30	$1.07	($0.96)	-2.1%	($0.97)	-2.1%
150	$49.05	$47.87	$46.68	$1.14	($1.18)	-2.4%	($1.19)	-2.5%
160	$51.87	$50.47	$49.07	$1.22	($1.40)	-2.7%	($1.41)	-2.8%
170	$54.69	$53.07	$51.45	$1.29	($1.62)	-3.0%	($1.62)	-3.1%
180	$57.51	$55.68	$53.83	$1.37	($1.84)	-3.2%	($1.84)	-3.3%
190	$60.33	$58.28	$56.22	$1.45	($2.05)	-3.4%	($2.06)	-3.5%
200	$63.16	$60.88	$58.60	$1.52	($2.27)	-3.6%	($2.28)	-3.7%
210	$65.98	$63.48	$60.98	$1.60	($2.49)	-3.8%	($2.50)	-3.9%
220	$68.80	$66.09	$63.37	$1.67	($2.71)	-3.9%	($2.72)	-4.1%
230	$71.62	$68.69	$65.75	$1.75	($2.93)	-4.1%	($2.94)	-4.3%
240	$74.44	$71.29	$68.13	$1.83	($3.15)	-4.2%	($3.16)	-4.4%
250	$77.26	$73.89	$70.52	$1.90	($3.37)	-4.4%	($3.38)	-4.6%
350	$105.48	$99.92	$94.35	$2.66	($5.56)	-5.3%	($5.57)	-5.6%
500	$147.81	$138.96	$130.11	$3.80	($8.85)	-6.0%	($8.85)	-6.4%
600	$173.59	$162.76	$151.93	$4.57	($10.83)	-6.2%	($10.83)	-6.7%
700	$199.36	$186.55	$173.74	$5.33	($12.81)	-6.4%	($12.81)	-6.9%
800	$225.14	$210.35	$195.56	$6.09	($14.79)	-6.6%	($14.79)	-7.0%
900	$250.92	$234.14	$217.38	$6.85	($16.77)	-6.7%	($16.77)	-7.2%
1,000	$276.69	$257.94	$239.19	$7.61	($18.75)	-6.8%	($18.75)	-7.3%
5,000	$781.57	$762.81	$744.06	$38.05	($18.76)	-2.4%	($18.75)	-2.5%
10,000	$1,412.67	$1,393.89	$1,375.15	$76.09	($18.78)	-1.3%	($18.75)	-1.3%
20,000	$2,674.88	$2,656.06	$2,637.32	$152.18	($18.81)	-0.7%	($18.75)	-0.7%
30,000	$3,937.08	$3,918.24	$3,899.49	$228.27	($18.84)	-0.5%	($18.75)	-0.5%

Notes: Present and proposed bills include present and proposed SC#5 base rates, the balancing charge assuming the supplier takes SC#8 storage service, and other rate adjustments applicable to SC#5 customers. The balancing amount calculates the balancing charge only.

APPENDIX G

MARGINAL CUSTOMER COST OF SERVICE

ROCHESTER GAS AND ELECTRIC
GAS DEPARTMENT
MARGINAL CUSTOMER COST OF SERVICE STUDY

Regulatory Affairs Department

Table of Contents

Introduction 1

Customer-Related Distribution Investment and Expenses. . . . 1

Schedules. 6

Appendix C 15

Rochester Gas and Electric Corporation
Marginal Customer Cost of Gas Service - 1998

Introduction

The goal of this study is to provide a starting point for the rate design process by calculating prices for the customer cost portion of gas service based upon marginal costs. The following schedules reflect an update to only the customer cost portion of the Marginal Cost of Gas Service Study for Twelve Months Ending December 31, 1996 submitted in Case 95-G-0674. Costs relating to increased load were not analyzed for this study since there have been no material changes from 1996.

The theoretical underpinnings of this study emulate those of the marginal cost of electric service study, which were first formulated by National Economic Research Associates (NERA) in "How to Quantify Marginal Costs", published on March 10, 1977. This study generally follows the principles laid out in that document. However, over time much effort has been devoted to improving the methods of marginal cost analysis. Individual utilities, the staff of the New York State Public Service Commission (NYPSC), and the Marginal Cost Working Group (a multi-utility group organized by NERA) have all contributed to this effort. The current analysis is an attempt to utilize the most reliable and accurate methods known.

The general process of this study is as follows: First, expenses and investment required to supply an additional customer are calculated for the functional area of customer-related distribution and other customer-related activities. Next, annualized marginal costs are developed by applying economic carrying charge rates to marginal investment, and adding expenses and revenue requirements for working capital. Finally, customer costs by customer group are stated in terms of a annual and monthly charge.

Customer-Related Distribution Investment and Expenses

Customer-related costs are the minimum investment that the company must make in order to provide a customer with access to the gas system, along with the expenses associated with the addition of such a customer. Customer-related costs can be broken out into two main categories: customer-related distribution costs, and other customer-related costs. Costs in both categories are further divided into expenses and carrying costs on investment. We will first look at the development of customer-related distribution investment.

In order to accurately quantify customer-related distribution costs it is first necessary to define which investment is to be considered. The traditional definition of customer-related distribution is equipment that is installed simply to facilitate the addition of a customer and is not related to the load that is being added. Additions to the distribution system are not designed given only the number of customers that must be served, but also given the load that the new facilities must carry. Strictly speaking, then, there is no distribution investment that is solely tied to the number of customers added. There is, however, a portion of the distribution system that is installed when customers are added and does not vary with the load on those facilities. These facilities are the distribution mains that deliver gas directly to the customers. It is this portion of the distribution system investment that we define as customer-related. Having defined customer-related distribution investment, it must now be quantified.

To quantify investment in customer-related distribution facilities, residential installations were analyzed. Distribution facilities for residential heating customers are initially sized so that they will not have to be replaced or upgraded regardless of the load that those customers place on the system. Thus, this investment fits the definition of customer-related distribution. Residential customers are the smallest customers on the distribution system and therefore the customer-related distribution investment to serve them is the smallest of any customer. We therefore consider the amount of customer-related distribution investment for any size customer to be the same as that for a residential heating customer. Any further investment required for a larger customer due to its size is considered load-related.

To determine actual customer-related distribution investment per customer, a group of typical residential installation projects for 1997 was examined. Residential construction consists of townhouses, new home subdivisions, and extensions to existing homes. Booked investment in projects from each of the three residential types was obtained from the Energy Systems Development department. Average investment per customer was produced and weighted by residential type. The results of this process are shown on Schedule 2, where the figures are adjusted upward to 1998 price levels. These results are transferred to

Rochester Gas and Electric Corporation
Marginal Customer Cost of Gas Service - 1998

Schedule 5.

A separate analysis was performed to determine investment in all other customer-related equipment. This is the investment necessary to bring the gas from the main into the customer's facility. This includes the service lateral, the meter and its associated hardware, the regulator, and the relief valve. This equipment is sized on the basis of the maximum load it must accommodate. Therefore, investment will be different for different size customers. The exception to this is the residential class, for which a standardized installation is used. On Schedule 5, customer-related costs are shown for eight customer-size groups. The definition of these groups is shown on table 1 below. The Gas Field Operations department provided updated costs for the average length of service lateral for each size group and a weighted average cost per customer was achieved for each size group. This appears on line 9. Similarly, using updated costs from the Strategic Supply Management department, the appropriate metering equipment, regulator, and relief valve were determined and a weighted average cost was calculated for each size group as seen on lines 10 and 11. General and common plant loading is added to all capital investment and the proper economic carrying charge rate is applied. Finally, an administrative and general expense loading factor is applied from Worksheet B to produce annual capital costs.

Customer-related expenses are those which are associated with the operation or maintenance of customer-related investment, and those expenses that increase with the addition of a customer. Customer-related distribution expenses are those expenses that are related to operating and maintaining the customer-related portion of the distribution system. Expenses related to the growth in number of customers are identified above. Operation and maintenance expenses on lines 20 and 21 of Schedule 5 include all other customer-related operation & maintenance activities and are assigned to the size groups in a manner that appropriately reflects their causation. The method by which each account was assigned is detailed in Appendix C. Customer accounts expenses include amounts related to reading meters, rendering customer bills and similar services. These costs are booked in accounts 901 through 906, excluding accounts 903.2 and 904. Expenses incurred for the purpose of collecting past due amounts from customers, and amounts written of as uncollectible are excluded from this analysis. Customer service expenses are comprised of activities related to assisting customers in their use of energy and providing relevant information. These expenses are booked in accounts 909 through 912, and shown on lines 22 and 23. Customer accounts expenses and customer service expenses are assigned to size groups in an appropriate manner. Again, the method used for each account can be found in Appendix C. An administrative and general expense loading factor is applied to all expenses to arrive at total annual expenses.

Working capital is calculated base on investment and expenses, and the related revenue requirement is developed. Total annual customer-related costs, then, are the sum of annual capital costs, annual expenses, and revenue requirement for working capital as shown on line 31.

Table 1

Size Group	Definition
1	Annual Usage > 25,000 DT
2	Annual Usage 15,001 to 25,000 DT
3	Annual Usage 5,001 to 15,000 DT
4	Annual Usage 1,001 to 5,000 DT
5	Annual Usage 151 to 1000 DT
6	Annual Usage 41 to 150 DT
7	Annual Usage 12 to 40 DT
8	Annual Usage < 12 DT

Rochester Gas and Electric Corporation
Marginal Customer Cost of Gas Service - 1998

Schedules & Worksheets

Rochester Gas and Electric Corporation
Marginal Cost of Gas Service
Customer-Related Distribution Costs
12 Months Ending December, 1998

Residential Type	Investment per Cust ($ 1998)	Weighting Factors	Weighted Average Investment
Townhouses	$371.90	29.66%	
Extension to Existing Homes	$3,258.97	7.27%	$611.12
New Homes Subdivision	$418.28	63.07%	

Customer-Related Distribution System Cost, 1998$/Cust	$611.12
Estimated Inflation Multiplier	1.0000
Customer-Related Distribution System Cost, 1998$/Cust	$611.12

Notes: Weighted average investment input to Schedule 5, Marginal Customer-Related Units Costs.

Rochester Gas and Electric Corporation
Marginal Cost of Gas Service
Marginal Customer-Related Unit Costs
12 Months Ending December 1998

	Group 1	Group 2	Group 3
Capital Costs - Customer-Related Distribution Facilities			
1) Customer-Related Distribution Investment (1998 $)	611.12	611.12	611.12
2) General and Common Plant Loading	13.01%	13.01%	13.01%
3) 1997-1998 Estimated Inflation Multiplier	1.00	1.00	1.00
4) Total Marginal Investment (1998 $)	690.61	690.61	690.61
5) Economic Carrying Charge Rate	10.82%	10.82%	10.82%
6) Administrative and General Loading	0.81%	0.81%	0.81%
7) Total Annual Carrying Charge Rate	11.63%	11.63%	11.63%
8) Total Annual Capital Cost (1998 $)	80.34	80.34	80.34
Capital Costs - Service and Metering Equipment			
9) Incremental Service Investment (1998 $)	2,624.17	1,083.58	885.03
10) Incremental Meter Investment (1998 $)	14,542.54	4,957.24	3,125.21
11) Incremental Regulator and Relief Valve Investment (1998 $)	2,548.27	805.17	336.12
12) 1997-1998 Estimated Inflation Multiplier	1.00	1.00	1.00
13) General and Common Plant Loading	13.01%	13.01%	13.01%
14) Total Marginal Investment (1998 $)	22,279.26	7,736.43	4,911.68
15) Economic Carrying Charge Rate	11.07%	11.07%	11.07%
16) Administrative and General Loading	0.81%	0.81%	0.81%
17) Total Annual Carrying Charge Rate	11.88%	11.88%	11.88%
18) Total Annual Capital Cost (1998 $)	2,647.43	919.31	583.65
Operation and Maintenance Expense			
19) Customer-Related Dist. Expenses (1997 $)	7.44	7.44	7.44
0) Operation Expenses (1997 $)	420.19	164.60	116.20
.1) Maintenance Expenses (1997 $)	19.40	24.09	33.91
22) Customer Accounts Expenses (1997 $)	102.47	87.93	80.98
23) Customer Service Expenses (1997 $)	1,844.94	320.94	140.42
24) 1997-1998 Estimated Inflation Multiplier	1.02	1.02	1.02
25) Administrative and General Loading	32.11%	32.11%	32.11%
26) Total Annual Expenses (1998 $)	3,232.89	816.86	511.65
Working Capital			
27) Materials and Supplies, Prepayments	37.62	13.79	9.16
28) O&M Expense Allowance	404.11	102.11	63.96
29) Total Cash Working Capital	441.73	115.89	73.11
30) Revenue Requirement for Working Capital (1998 $)	49.66	13.03	8.22
31) Total Customer-Related Marginal Costs (1998 $)	6,010.31	1,829.53	1,183.86
32) Monthly Customer-Related Marginal Costs (1998 $)	500.86	152.46	98.65

Notes:
1) Schedule 2
2) Worksheet C
3) Schedule 1
4) ln(1)*[1+ln(2)]*ln(3)
5) Schedule 7
6) Worksheet B
8) line (4) * line (7)
9) Customer Cost Study
10) Customer Cost Study
11) Customer Cost Study
14) [ln(9)+ln(10)+ln(11)] * ln(12) * [1 + ln(13)]
17) line(15) + line(16)
19) Customer Cost Study
20) Customer Cost Study
21) Customer Cost Study
22) Customer Cost Study
23) Customer Cost Study
26) [Sum of lines(19-23)] * ln(24) * [1+ln(25)]
27) [ln(8) + ln(18)] * 1.38%
28) line(26) * 12.50% assumes 45 day time lag
29) line(27) + line (28)
30) line(29) * 11.24%
31) sum lines(8,18,26,30)

Rochester Gas and Electric Corporation
Marginal Cost of Gas Service
Marginal Customer-Related Unit Costs
12 Months Ending December 1998

	Group 4	Group 5	Group 6
Capital Costs - Customer-Related Distribution Facilities			
1) Customer-Related Distribution Investment (1998 $)	611.12	611.12	611.12
2) General and Common Plant Loading	13.01%	13.01%	13.01%
3) 1997-1998 Estimated Inflation Multiplier	1.00	1.00	1.00
4) Total Marginal Investment (1998 $)	690.61	690.61	690.61
5) Economic Carrying Charge Rate	10.82%	10.82%	10.82%
6) Administrative and General Loading	0.81%	0.81%	0.81%
7) Total Annual Carrying Charge Rate	11.63%	11.63%	11.63%
8) Total Annual Capital Cost (1998 $)	80.34	80.34	80.34
Capital Costs - Service and Metering Equipment			
9) Incremental Service Investment (1998 $)	766.32	586.87	585.00
10) Incremental Meter Investment (1998 $)	1,164.30	198.93	96.75
11) Incremental Regulator and Relief Valve Investment (1998 $)	98.51	26.08	25.72
12) 1997-1998 Estimated Inflation Multiplier	1.00	1.00	1.00
13) General and Common Plant Loading	13.01%	13.01%	13.01%
14) Total Marginal Investment (1998 $)	2,293.05	917.48	799.48
15) Economic Carrying Charge Rate	11.07%	11.07%	11.07%
16) Administrative and General Loading	0.81%	0.81%	0.81%
17) Total Annual Carrying Charge Rate	11.88%	11.88%	11.88%
18) Total Annual Capital Cost (1998 $)	272.48	109.02	95.00
Operation and Maintenance Expense			
19) Customer-Related Dist. Expenses (1997 $)	7.44	7.44	7.44
20) Operation Expenses (1997 $)	59.64	31.18	30.55
21) Maintenance Expenses (1997 $)	17.52	0.47	0.39
22) Customer Accounts Expenses (1997 $)	34.18	17.96	23.25
23) Customer Service Expenses (1997 $)	36.62	4.09	1.96
24) 1997-1998 Estimated Inflation Multiplier	1.02	1.02	1.02
25) Administrative and General Loading	32.11%	32.11%	32.11%
26) Total Annual Expenses (1998 $)	209.81	82.57	85.84
Working Capital			
27) Materials and Supplies, Prepayments	4.87	2.61	2.42
28) O&M Expense Allowance	26.23	10.32	10.73
29) Total Cash Working Capital	31.09	12.93	13.15
30) Revenue Requirement for Working Capital (1998 $)	3.50	1.45	1.48
31) Total Customer-Related Marginal Costs (1998 $)	566.12	273.38	262.66
32) Monthly Customer-Related Marginal Costs (1998 $)	47.18	22.78	21.89

Notes:
1) Schedule 2
2) Worksheet C
3) Schedule 1
4) ln(1)*[1+ln(2)]*ln(3)
5) Schedule 7
6) Worksheet B
8) line (4) * line (7)
9) Customer Cost Study
10) Customer Cost Study
11) Customer Cost Study
14) [ln(9)+ln(10)+ln(11)] * ln(12) * [1 + ln(13)]
17) line(15) + line(16)
19) Customer Cost Study
20) Customer Cost Study
21) Customer Cost Study
22) Customer Cost Study
23) Customer Cost Study
26) [Sum of lines(19-23)] * ln(24) * [1+ln(25)]
27) [ln(8) + ln(18)] * 1.38%
28) line(26) * 12.50% assumes 45 day time lag
29) line(27) + line (28)
30) line(29) * 11.24%
31) sum lines(8,18,26,30)

Rochester Gas and Electric Corporation
Marginal Cost of Gas Service
Marginal Customer-Related Unit Costs
12 Months Ending December 1998

	Group 7	Group 8
Capital Costs - Customer-Related Distribution Facilities		
1) Customer-Related Distribution Investment (1998 $)	611.12	611.12
2) General and Common Plant Loading	13.01%	13.01%
3) 1997-1998 Estimated Inflation Multiplier	1.00	1.00
4) Total Marginal Investment (1998 $)	690.61	690.61
5) Economic Carrying Charge Rate	10.82%	10.82%
6) Administrative and General Loading	0.81%	0.81%
7) Total Annual Carrying Charge Rate	11.63%	11.63%
8) Total Annual Capital Cost (1998 $)	80.34	80.34
Capital Costs - Service and Metering Equipment		
9) Incremental Service Investment (1998 $)	585.00	585.00
10) Incremental Meter Investment (1998 $)	96.75	96.75
11) Incremental Regulator and Relief Valve Investment (1998 $)	25.72	25.72
12) 1997-1998 Estimated Inflation Multiplier	1.00	1.00
13) General and Common Plant Loading	13.01%	13.01%
14) Total Marginal Investment (1998 $)	799.48	799.48
15) Economic Carrying Charge Rate	11.07%	11.07%
16) Administrative and General Loading	0.81%	0.81%
17) Total Annual Carrying Charge Rate	11.88%	11.88%
18) Total Annual Capital Cost (1998 $)	95.00	95.00
Operation and Maintenance Expense		
19) Customer-Related Dist. Expenses (1997 $)	7.44	7.44
20) Operation Expenses (1997 $)	29.99	29.99
21) Maintenance Expenses (1997 $)	0.38	0.38
22) Customer Accounts Expenses (1997 $)	23.16	23.12
23) Customer Service Expenses (1997 $)	0.70	0.32
24) 1997-1998 Estimated Inflation Multiplier	1.02	1.02
25) Administrative and General Loading	32.11%	32.11%
26) Total Annual Expenses (1998 $)	83.27	82.70
Working Capital		
27) Materials and Supplies, Prepayments	2.42	2.42
28) O&M Expense Allowance	10.41	10.34
29) Total Cash Working Capital	12.83	12.76
30) Revenue Requirement for Working Capital (1998 $)	1.44	1.43
31) Total Customer-Related Marginal Costs (1998 $)	260.05	259.47
32) Monthly Customer-Related Marginal Costs (1998 $)	21.67	21.62

Notes:
1) Schedule 2
2) Worksheet C
3) Schedule 1
4) ln(1)*[1+ln(2)]*ln(3)
5) Schedule 7
6) Worksheet B
8) line (4) * line (7)
9) Customer Cost Study
10) Customer Cost Study
11) Customer Cost Study
14) [ln(9)+ln(10)+ln(11)] * ln(12) * [1 + ln(13)]
17) line(15) + line(16)
19) Customer Cost Study
20) Customer Cost Study
21) Customer Cost Study
22) Customer Cost Study
23) Customer Cost Study
26) [Sum of lines(19-23)] * ln(24) * [1+ln(25)]
27) [ln(8) + ln(18)] * 1.38%
28) line(26) * 12.50% assumes 45 day time lag
29) line(27) + line (28)
30) line(29) * 11.24%
31) sum lines(8,18,26,30)

Rochester Gas and Electric Corporation
Marginal Cost of Gas Service
Computation of Loading Factors For Administrative and General Expenses
and Social Security and Unemployment Taxes
(000's)

	FERC Account Number	Account	1997	1996	1995	1994	1993	1992	1991	1990	Est. for Planning Period
		APPLICABLE TO EXPENSES									
(1)	925.0	Injuries and damages	1,050	2,012	2,629	1,836	2,071	1,461	1,388	2,193	
(2)	926.0	Employee pensions & benefits	6,340	5,295	4,068	6,593	6,228	5,782	4,754	4,520	
(3)	929.0	Duplicate charges-cr	0	0	0	0	0	0	0	0	
(4)	408.1	Soc. Sec. & unemplmt. ins. tax	3,013	2,748	2,069	2,261	2,004	2,319	2,239	1,986	
(5)		TOTAL applicable to O&M	10,403	10,055	8,766	10,690	10,303	9,562	8,381	8,699	
(6)		TOTAL O&M Expenses [1]	33,226	33,097	32,221	29,427	29,880	28,926	26,702	26,577	
		A&G Loading factor applicable to O&M Expenses (5) / (6)	31.3%	30.4%	27.2%	36.3%	34.5%	33.1%	31.4%	32.7%	32.1%
		APPLICABLE TO INVESTMENT									
(7)	881	Rents (from Distribution)	30	29	40	39	38	42	38	41	
(8)	931.0	Rents	2,947	3,290	2,590	2,387	1,693	739	1,071	1,521	
(9)	932.0	Maintenance of general plant	139	250	404	1,474	1,985	1,904	1,891	1,563	
(10)		TOTAL applicable to investment	3,116	3,569	3,034	3,900	3,716	2,685	3,000	3,125	
(11)		TOTAL gross plant as of December 31 [2]	464,161	436,655	429,448	417,740	400,509	384,528	360,468	340,242	
		A&G loading factor applicable to investment (10) / (11)	0.7%	0.8%	0.7%	0.9%	0.9%	0.7%	0.8%	0.9%	0.8%

[1] Excludes production expenses, and A&G expenses.
[2] Includes common plant allocated to Gas Department

Rochester Gas and Electric Corporation
Marginal Cost of Gas Service
Computation of Loading Factors For Administrative and General Expenses
and Social Security and Unemployment Taxes

Source: Lines 1-3 and 7-9: PSC Report
Line 4: Ibid., (NYS Unempl, Disability; Federal Unempl, Soc Sec)
Line 6: Ibid., (Total Gas M&O, less Production, A&G)
Line 11: Ibid

Notes:

Use same principles as in electric marginal cost study. The following are not considered marginal. They are:

Expenses:
920.0 Admin & general salaries
921.0 Office supplies and expenses
922.0 Admin expenses transferred-cr
930.1 Gen. advertising expenses
930.2 Misc. general expenses

Investment:
923.0 Outside services employed
924.0 Property insurance
927.0 Franchise requirements
928.0 Regulatory Comm. expenses

Rochester Gas and Electric Corporation
Marginal Cost of Gas Service
Derivation of General Plant Loading Factor

	1997	1996	1995	1994	1993	Est. for Planning Period
	(1)	(2)	(3)	(4)	(5)	
(1) Gas Plant in Service ($000's)	416,989	391,231	382,071	370,205	356,484	
(2) General Plant ($000's)	3,254	3,197	2,917	2,661	2,267	
(3) Common Utility Plant (Gas)	47,172	45,424	47,377	47,535	44,025	
(4) General Plus Common Plant (2)+(3)	50,426	48,621	50,294	50,196	46,292	
(5) Gas Plant less General (1)-(2)	413,735	388,034	379,154	367,544	354,217	
(6) General and Common Loading Factor(4)/(5)	12.19%	12.53%	13.26%	13.66%	13.07%	13.01%

Source: line (1): PSC Report, page 62, line 112.
line (2): Ibid., line 108
line (3): Ibid, page 356.
line (6), column (6): Average of 1993-1997

Rochester Gas and Electric Corporation
Marginal Cost of Gas Service
Development of Loading Factors for
Prepayments and Materials and Supplies

	1997	1996	1995	1994	1993	Est. for Planning Period
(1) Gas Plant in Service	416,989	391,231	382,071	370,205	356,484	
(2) Common Plant allocated to Gas	47,172	45,424	47,377	47,535	44,025	
(3) Total Gas Plant (1)+(2)	464,161	436,655	429,448	417,740	400,509	
(4) Total Utility Plant in Service	2,987,573	2,931,680	2,856,957	2,787,117	2,712,829	
(5) Gas Plant as % of Total (3)/(4)	15.54%	14.89%	15.03%	14.99%	14.76%	
Materials and Supplies						
(6) A/c 154 Assigned to Electric	7,775	8,886	8164	2,447	2,483	
(7) Balance of A/c 154	1,905	2,116	2,016	10,262	10,414	
(8) A/c's 155 and 163	0	0	0	0	746	
(9) Allocation of Unassigned Amounts to Gas Department	1,905	2,116	2,016	1,538	1,648	
(10) Total Materials and Supplies	1,905	2,116	2,016	1,538	1,648	
Prepayments						
(11) Total Account 165	29,573	22,029	24,533	23,535	21,563	
(12) Account 165 Allocated to Gas	5,323	4,836	3,688	3,527	3,183	
(13) Total Prepayments and Materials and Supplies (10)+(12)	7,228	6,952	5,704	5,066	4,831	
(14) Prepayments and Materials and Supplies Loading Factor (13)/(3)	1.56%	1.59%	1.33%	1.21%	1.21%	1.38%

Sources:
(1) & (2) Page 1
(4) PSC Report; 1994 & 1993 data adjusted to match PSC report;
(6) to (8) FERC Form I, PSC Report, or backup to ebcap calculations
Information for 95-97 already split elec/gas; Did not need to allocate
(9) line (5) times sum of lines (7) and (8); or ebcap backup for 1996, 1997
(10) same as line (9)
(11) FERC Form I, PSC Report, or ebcap backup
(12) line (5) times line (11); or ebcap backup

Rochester Gas and Electric Corporation
Marginal Customer Cost of Gas Service - 1998

APPENDIX C
Methods of Assigning Expenses to Customer Groups

Rochester Gas and Electric Corporation
Marginal Customer Cost of Gas Service - 1998

Operation and Maintenance Expenses

a/c 874.10 - Public Building Inspection
Includes only dollars charged by Strategic Supply Management Dept. Assigned to size groups based on number of rotary meters

a/c 878.10 - Remove and Reset Meters and House Regulators
Assigned using number of rotary and diaphragm meters weighted by the frequency of changeout and the time involved

a/c 878.20 - Turn-on/Shut-off, Misc. Meter and House Regulator Exp.
All dollars in this account assigned to residential group

a/c 879.10 - Investigate Service Complaints
Assigned based on number of non-residential customers

a/c 879.12 - Investigate Gas Leak and Odor Complaints
All dollars in this account assigned to residential group

a/c 879.20 to 879.23 and 879.33 - Servicing Residential Appliances and Servicing Spaceheating Equipment
All dollars in these accounts assigned to residential group

a/c 879.24 - Survey and Inspection of School Appliances
Assigned based on number of municipal customers

a/c 879.30 - Servicing Commercial Appliances
Assigned based on number of commercial customers

a/c 879.31 - Servicing Industrial Appliances
Assigned based on number of industrial customers

a/c 880.10 - Maps and Records Expenses
Assigned to size groups based on total marginal investment in each group

a/c 880.20 - Other Distribution Office Expenses
Same as a/c 880.10

a/c 892.10 to 892.30 - Maintenance of Services
Assigned based on marginal investment in services

a/c 892.40 - Service and Curbcock Inspection
Dollars for rotary meters in each group based on actual frequency, time and labor rate. Remaining dollars to each

group based on number of diaphragm meters.

a/c 893.11 - Meter Installation Maintenance
Assigned based on marginal investment in meters

Customer Accounts Expenses

a/c 901.00 - Supervision
Assigned based on dollars in accounts 902-903 and 905-906

a/c 902.00 - Meter Reading Expenses
Assigned based on number of customers weighted by average meter reads per year and average time per read.

a/c 903.10 - Cashiers Salaries and Expenses and Agency Fees
Assigned based on total number of customers

a/c 903.30 - Credit Investigation and Records
Assigned based on total number of customers

a/c 903.40 - Customer Contracts and Orders
Assigned based on total number of customers

a/c 903.50 - Customer Billing and Accounting
Assigned based on number of bills rendered adjusted for number of hand bills

a/c 903.70 - Information Systems
Assigned based on total number of customers

a/c 905.00 - Miscellaneous Customer Accounts Expenses
Assigned based on total number of customers

Customer Service Expenses

a/c 909.01 - Supervision, Residential
All dollars assigned to residential group

a/c 909.02 - Supervision, Commercial
Assigned based on commercial consumption

a/c 909.03 - Supervision, Industrial
Assigned based on industrial consumption

a/c 909.06 - Supervision, Marketing Communications
Assigned based on total consumption

Rochester Gas and Electric Corporation
Marginal Customer Cost of Gas Service - 1998

a/c 910.01 - Customer Assistance, Residential
All dollars assigned to residential group

a/c 910.02 - Customer Assistance, Commercial
Assigned based on commercial consumption

a/c 910.03 - Customer Assistance, Industrial
Assigned based on industrial consumption

a/c 910.05 to 910.09 - Consumer Relations, Dealer Relations, and Builders Service
All dollars assigned to residential group

a/c 910.10 - Area Development
Assigned based on total consumption

a/c 910.21 - Customer Instruction, Residential
All dollars assigned to residential group

a/c 911.01 - Informational Advertising, Residential
All dollars assigned to residential group

a/c 911.02 - Informational Advertising, Commercial
Assigned based on commercial consumption

a/c 911.03 - Informational Advertising, Industrial
Assigned based on industrial consumption

a/c 911.05 - Informational Advertising, Consumer Relations
All dollars assigned to residential group

a/c 912.01 - Miscellaneous Customer Service, Residential
All dollars assigned to residential group

a/c 912.02 - Miscellaneous Customer Service, Commercial
Assigned based on commercial consumption

a/c 912.03 - Miscellaneous Customer Service, Industrial
Assigned based on industrial consumption

a/c 912.05 - Miscellaneous Customer Service, Consumer Relations
All dollars assigned to residential group

a/c 912.72 to 912.74 - Information Systems
Assigned based on total customers

APPENDIX H

PROPOSED TRANSPORTATION GAS TARIFF CHANGES

Proposed Changes to SC #3

Leaf #	Section	Change	Comments
92	Applicability	Eliminate items b through d; add requirement to contract with a qualified supplier for gas supply (one supplier per metering point) or to become qualified as a direct customer under SC #6	Move item b to rule 2.A.2, items c & d to SC #6
92	Customer Responsibility	Eliminate existing language; add responsibility to inform supplier and RG&E of Human Needs status and, if applicable, to certify that dual-fuel equipment has been tested	Remaining responsibilities to be moved to SC #6
92-A	Rate	Eliminate section on balancing charge	Move to SC #6
93	Rate	Modify description of Firm Transportation Rate Adjustment Statement to eliminate references to balancing charges and the various related costs.	
93-A	Operational Flow Order	Eliminate section	Language already present in SC #6
93-B to 96-B	Balancing Service	Eliminate section	Move to SC #6
96-C	Balance Control Options	Eliminate section	Move to supplier manual
96-D	Imbalance Trading	Eliminate section	Move to SC #6
96-D & 96-E	Standby Service	Eliminate section	Service expires on 3/31/2000.
97	Loss Allowance	Eliminate section	Move to SC #6
97 & 98	Special Provisions	Eliminate Nos. 2, 3, 4 and 5	Move No. 2 to SC #6, balancing charges; no. 3 is already provided for under rule 7.B; language for 1st par. of no. 4 is already present in SC #6; 2nd par. of no. 4 should be moved to Rule 6; no. 5 is obsolete

Proposed Changes to SC #5

Leaf #	Section	Change	Comments
103	Applicability	Eliminate items a, b and c; eliminate existing language on volume limitations; add new language limiting applicability to service points with annual volumes less than 5000 DT; eliminate existing language on migration limits.	Move item a to rule 2.A.2, item b already exists in SC #6, item c is unnecessary, language regarding migration limits is obsolete
104	Rate	Eliminate language regarding balancing charges.	Move to SC #6
105-A	SC No. 5 - Comprehensive Transportation Rate Adjustment Statement	Eliminate language regarding balancing charges.	Move to SC #6
106	Determination of daily contract quantity	Eliminate	Move to Supplier Manual
107	Special Provisions	Eliminate item no. 4	Already provided for under rule 7.B
108	Special Provisions	Eliminate items no. 8 through 10	Item no. 8 is unnecessary given other provisions of the tariff and supplier manual; Item no. 9 is not necessary; Move item no. 10 to supplier manual

PROPOSED CHANGES TO SC #6

Leaf #	Section	Change	Comments
13-C	Security	Add to calculation of security projected balancing charges under SC No. 6	
109	Applicability	Make applicable to suppliers serving SC No. 3 customers in addition to SC No. 5 customers; also make applicable to direct customers.	
109	Character of service	Add reference to SC No. 3, as well as SC No. 5	
109	Rate	Reword as follows: "Rates and charges pursuant to this Service Classification are as specified under Capacity Assignment, Balancing Charges, and under Service Classification No. 6 - Supplier Service Rate Adjustment Statement."	References to Capacity Release and Supplier Responsibility 5 are obsolete; Supplier Responsibility No. 1 will be incorporated in new section on balancing charges.
109	SC No. 6 - Supplier Service Rate Adjustment Statement	Add reference to balancing charges in last sentence.	
111 and 112	Nomination procedures	Eliminate	Move to Supplier Manual
New leaves	Balancing Charges	Add description of On-System and Citygate Balancing charges from SC No. 3 leaves 93-B to 96-B; add language regarding balancing charges from SC No. 6 leaf 104; and incorporate Supplier Responsibilities No. 1 and 3 from leaves 112 and 113	
New leaves	Imbalance Trading	Add language from SC No. 3 allowing imbalance trading between like pools serving SC No. 3	

Leaf #	Section	Change	Comments
		customers	
112	Supplier Responsibilities	Add new item 1 - "Supplier must adhere to operating practices and procedures as described in RG&E's Supplier Manual (and add reference to web site)."	
113	Supplier Responsibilities	Eliminate item no. 2	Redundant
114-A	Supplier Responsibilities	Clarify that item no. 8 applies only to load that transferred to transportation service after 11/1/96, and also to that portion of load at a service point that relates to human needs; eliminate sub-item (b).	First change is made necessary as a result of extending applicability to SC #3 suppliers; sub-item (b) is related to standby service which expires on March 31, 2000.
114-A	Supplier Responsibilities	Add description of switching fee from Rule 2.A.3 and eliminate from Rule 2.A.3.	
114-A and 114-B	Standby Service	Eliminate	Service expires on March 31, 2000.
115	Consumer Protections	Clarify that this section applies only to service provided to SC No. 5 customers	

APPENDIX I

MANAGING GAS DELIVERIES

Managing Deliveries - Recent History and Phase-In Plan

Date & reason for change	Responsible Entity	Fore-caster	Frequency of Change	Delivery Point Requirements	Hourly Flow Requirements	Assets Required
11/1/96 - PSC mandates small volume transport and revamping of balancing services	LDC Merchant	RG&E	Intraday nomination changes as necessary	Total system flows limited by physical flow capability at each city gate; varies with load conditions	Pipeline contracts must support hourly variations for total system load	CNG NN storage; firm transportation and storage contracts
	Suppliers serving large volume market	RG&E	Monthly with some intramonth changes	None	None	No requirements
	Suppliers serving small volume market	RG&E	Monthly	None	None	No requirements

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Date & reason for change	Responsible Entity	Fore-caster	Frequency of Change	Delivery Point Requirements	Hourly Flow Requirements	Assets Required
11/1/99 - RG&E requires seasonal planning to manage city gate constraints; PSC mandates 5 months capacity for firm loads	LDC Merchant	RG&E	Intraday nom changes as necessary	Total system flows limited by physical flow capability at each city gate; varies with load conditions	Pipeline contracts must support hourly variations for total system load	CNG NN storage; firm transportation and storage contracts
	Suppliers serving large volume market	RG&E	Monthly with some intramonth changes	Seasonal planning process; noms outside plan may be rejected	None	5 months firm primary capacity required for human needs loads
	Suppliers serving small volume market	RG&E	Monthly	Seasonal planning process; noms outside plan may be rejected	None	5 months firm primary capacity required

Date & reason for change	Responsible Entity	Fore-caster	Frequency of Change	Delivery Point Requirements	Hourly Flow Requirements	Assets Required
5/1/00 - CNG implements DPO/CSC service and flow restrictions	LDC Merchant	RG&E	Intraday nom changes as necessary	Total system flows limited by physical flow restrictions at each city gate	Pipeline contracts must support hourly variations for total system load less load served under CNG CSC service	CNG NN storage; firm transportation and storage contracts
	Suppliers serving daily metered transport customers	Supplier	Daily	Seasonal planning process; surcharge may be applied to volumes outside constraints; noms outside plan may be rejected	None; but CNG CSC service will support some hourly variations	CNG CSC service; 5 months firm primary capacity for human needs loads and post 11/1/96 transport loads
	Suppliers serving monthly metered transport customers	RG&E	Monthly, occasionally intramonth changes	Seasonal planning process; surcharge may be applied to volumes outside constraints; noms outside plan may be rejected	None	5 months firm primary capacity for human needs loads and post 11/1/96 transport loads

MANAGING DELIVERIES - RECENT HISTORY AND PHASE-IN PLAN

Date & reason for change	Responsible Entity	Fore-caster	Frequency of Change	Delivery Point Requirements	Hourly Flow Requirements	Assets Required
4/1/01 - RG&E adjusts CNG storage contract	LDC Merchant	RG&E	Intraday nom changes as neccesary	Total system flows limited by physical flow restrictions at each city gate	Delivery contracts must support expected hourly load variations	CNG NN storage; firm transportation and storage contracts
	Suppliers serving daily metered transport customers	Supplier	Daily	Seasonal planning process; surcharge may be applied to volumes outside constraints; noms outside plan may be rejected	Delivery contracts must support expected hourly load variations	CNG CSC service; 5 months firm primary capacity for human needs loads and post 11/1/96 transport loads
	Suppliers serving monthly metered transport customers	Supplier	Daily	Seasonal planning process; surcharge may be applied to volumes outside constraints; noms outside plan may be rejected	Delivery contracts must support expected hourly load variations	CNG CSC service; 5 months firm primary capacity for human needs loads and post 11/1/96 transport loads

Date & reason for change	Responsible Entity	Fore-caster	Frequency of Change	Delivery Point Requirements	Hourly Flow Requirements	Assets Required
5/1/02 - equalize responsibilities of all LSEs	Suppliers serving daily metered transport customers	Supplier	Intraday nom changes as necessary	Seasonal planning process; noms must always be within constraints for the forecast load level	Delivery contracts must support expected hourly load variations	CNG CSC service; primary firm capacity from city gate to a liquid trading point for all firm loads at all times.
	Suppliers serving monthly metered transport customers	Supplier	Intraday nom changes as necessary	Seasonal planning process; noms must always be within constraints for the forecast load level	Delivery contracts must support expected hourly load variations	CNG CSC service; primary firm capacity from city gate to a liquid trading point for all firm loads at all times.

ASSUMPTIONS:

1. CNGT's proposed DPO/CSC service and hourly flow limitations are implemented as proposed on 4/15/00. The LDC will take DPO service and retain an appropriate level of capacity associated with this service.
2. RG&E's proposed delivery point surcharge mechanism is implemented on 5/1/00 as proposed. LDC merchant continues to ensure that delivery point flows are within constraints until 5/1/02.
3. Hourly flows through Empire continue to be limited to 5% of daily flows, except when overruns are authorized. Hourly flow limits on through CNGT will be dependent upon DPO and related CSC entitlements.
4. Appropriate cash-out and penalty provisions accompany each of the changes outlined above.
5. On 5/1/00, daily balancing would become mandatory for large volume transport customers (AMR equipment is in place now). Other customers could opt in by requesting an AMR installation.
6. Daily balancing for monthly metered customer is now expected to take some time to implement due to information system requirements. RG&E would propose to accelerate implementation if possible.

KEY:

1. Responsible Entity. Refers to the entity bound by the requirements listed in the succeeding columns. Currently, customers over 5000 DT per year (large volume transport) are served under SC #3, and "aggregation" customers are served under SC #5. We envision that for delivery management purposes, in the future the company will begin to distinguish between daily and monthly metered customers.
2. Forecaster. Refers to the entity that is responsible for forecasting the daily or hourly requirements for the particular customer group being served.
3. Frequency of change. Refers to the frequency with which nominations may be changed.
4. Delivery point requirements. Refers to requirements applied to those delivering gas into the system regarding which city gate may be utilized and under what circumstances.
5. Hourly flow requirements. Refers to requirements applied to those delivering gas into the system regarding hourly flows of nominated gas.
6. Assets required. Refers to requirements applied to those delivering gas into the system regarding upstream assets that must be held in order to meet reliability, delivery point or hourly flow requirements.

APPENDIX J

DELIVERY POINT OPERATING CONSTRAINTS

Delivery Point Operating Constraints

RG&E's gas system operating constraints have been under continuous review since planning began for the Company's interconnection with Empire State Pipeline in the late 1980s. The most recent review was completed during the summer and fall of 1999 by RG&E's System Planning and Operations Engineering Department. This appendix describes the analysis of delivery point operating constraints, and the results of that analysis.

Data evaluated included actual gas deliveries from 2/1/95 through 3/31/99 by hour. These data were analyzed to determine the range of flow under the summer and winter RG&E transmission system configurations. For winter operations, a portion of the system operates at 350 psig maximum to increase the throughput capability of the system in order to meet winter peak loads. During the summer, the entire system operates at 250 psig maximum for increased operational flexibility as well as for safety reasons. Steps followed in development of the models were:

- Peak and minimum days for summer and winter transmission system configuration were determined.
- Intermediate points between the peak and minimum were selected for modeling.
- Flow data were adjusted to remove load served in the Pavilion district, which is served from the CNG system and is not part of the Rochester district load. Roughly 5% of the total load is located in the Pavilion district.
- Flow patterns throughout the day were analyzed to determine the relationship between peak and minimum hours for each of the selected modeling points. See Attachments 1 and 2 for typical hourly load profiles at various daily flow rates. The first graph shows hourly rates in dekatherms and the second shows the same data as a percent of daily flow.
- Load modeling was performed utilizing RG&E's flow modeling tool GUIDE (Gas Utility Interactive Decision Environment).
- Upstream pipeline operating restrictions were factored into the load model, including the 5% of daily nomination flow limit on the Empire system.

Peak hourly flow as a percentage of daily flow ranges from almost 7%, typically seen in the spring or fall, to less than 5% on peak or near peak days. The GUIDE model was run at the peak hour and minimum hour level for each of the selected modeling points. The scenarios were run to maximize the delivery of Empire gas and also to maximize the delivery of CNG gas. End point pressures were maintained at or above 180 psi in both cases. Finally, the results were evaluated against the pipeline hourly flow rate operating restrictions and the model was revised when necessary to stay within restrictions.

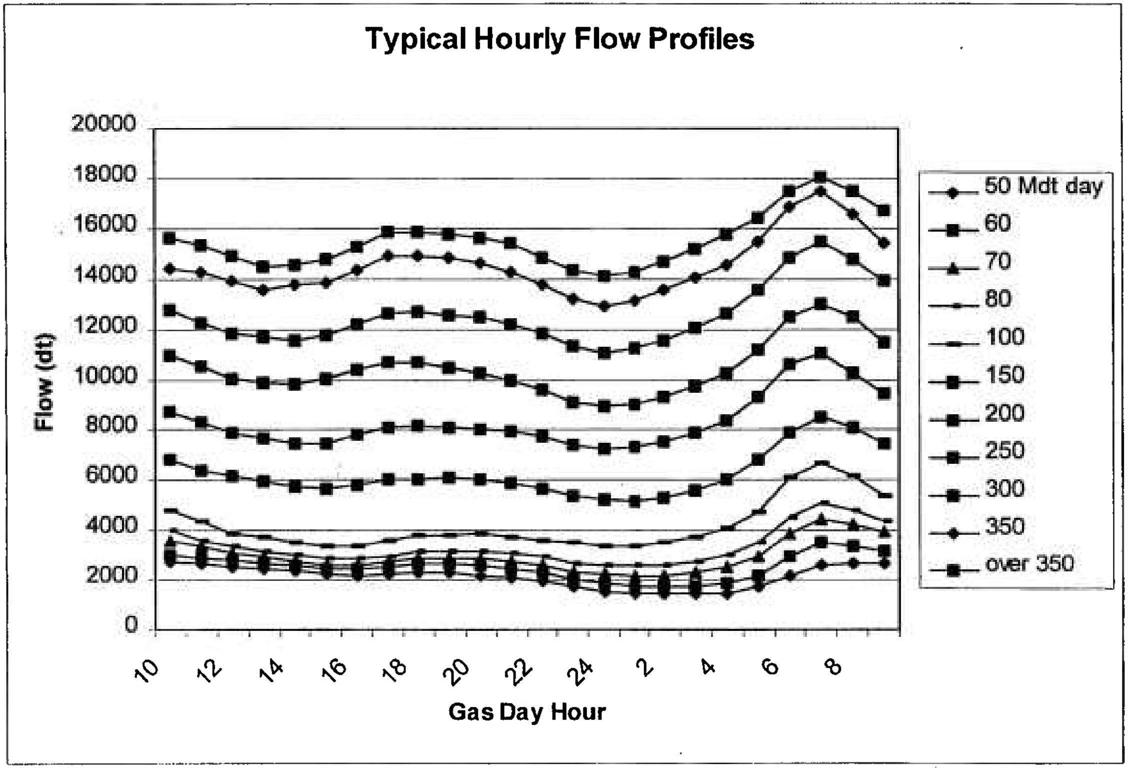
Next, an analysis of historical daily forecast accuracy (expected flows versus actual flows) was considered. Under RG&E's current system configuration, all variations between actual flows and nominated flows must be made up through the CNG connection. Daily forecast variances are handled primarily with No Notice Storage on that system. Therefore, an offset to the maximum Empire delivery was calculated to allow for days when the system load is less than the nominated load. The level of the offset varied somewhat over the range of flows based upon the analysis of historic forecast variances. The result of applying the offset to the physical maximum flow possible on Empire represents the maximum feasible planned delivery from Empire under different load conditions. The result accounts for the physical constraints of the system, normal hourly load fluctuations, and accuracy in forecasting system load.

Other factors affecting the model include:

- Isolated sections of the system that are connected only with CNG and cannot be supplied from Empire. This includes the Pavilion District and loads supplied directly off the 350 psig system during winter operation.
- Pressure loss in the RG&E transmission system limits the ability to supply gas from the gate stations to the extreme end points in the system, especially under high load conditions. Both CNG and Empire must supply minimum percentages of the load under peak conditions.

Graphs were prepared showing the system limitations at various daily flows in both the winter and summer configuration. See Attachment 3 for the winter model and Attachment 4 for the summer model.

The GUIDE model will continue to be updated for new loads. Delivery point constraints will change over time based on load growth and customer movement.



Typical Hourly Flow Profiles
20000
18000
16000
14000
12000
10000
8000
6000
4000
2000
0
Flow (dt)
10
12
14
16
18
20
22
24
2
4
6
8
Gas Day Hour
50 Mdt day
60
70
80
100
150
200
250
300
350
over 350

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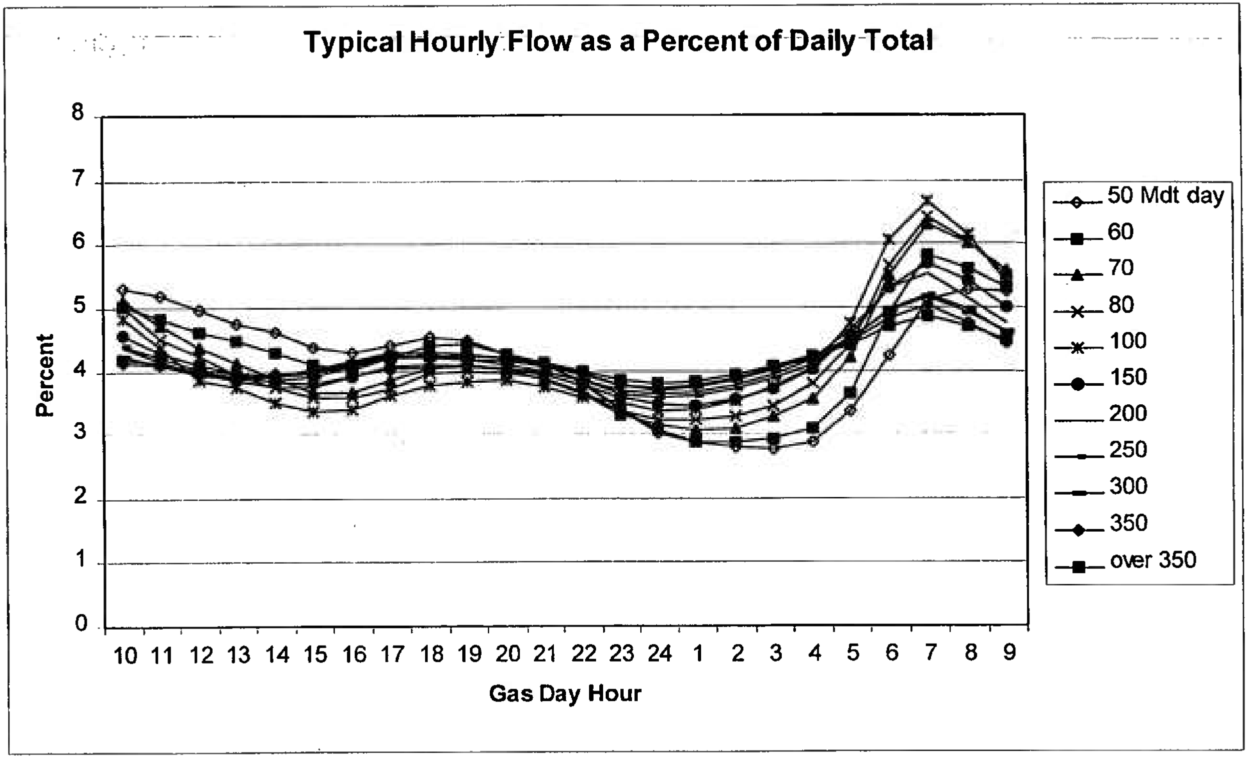
Typical Hourly Flow as a Percent of Daily Total
Percent
0
1
2
3
4
5
6
7
8
10 11 12 13 14 15 16 17 18 19 20 21 22 23 24 1 2 3 4 5 6 7 8 9
Gas Day Hour
50 Mdt day
60
70
80
100
150
200
250
300
350
over 350

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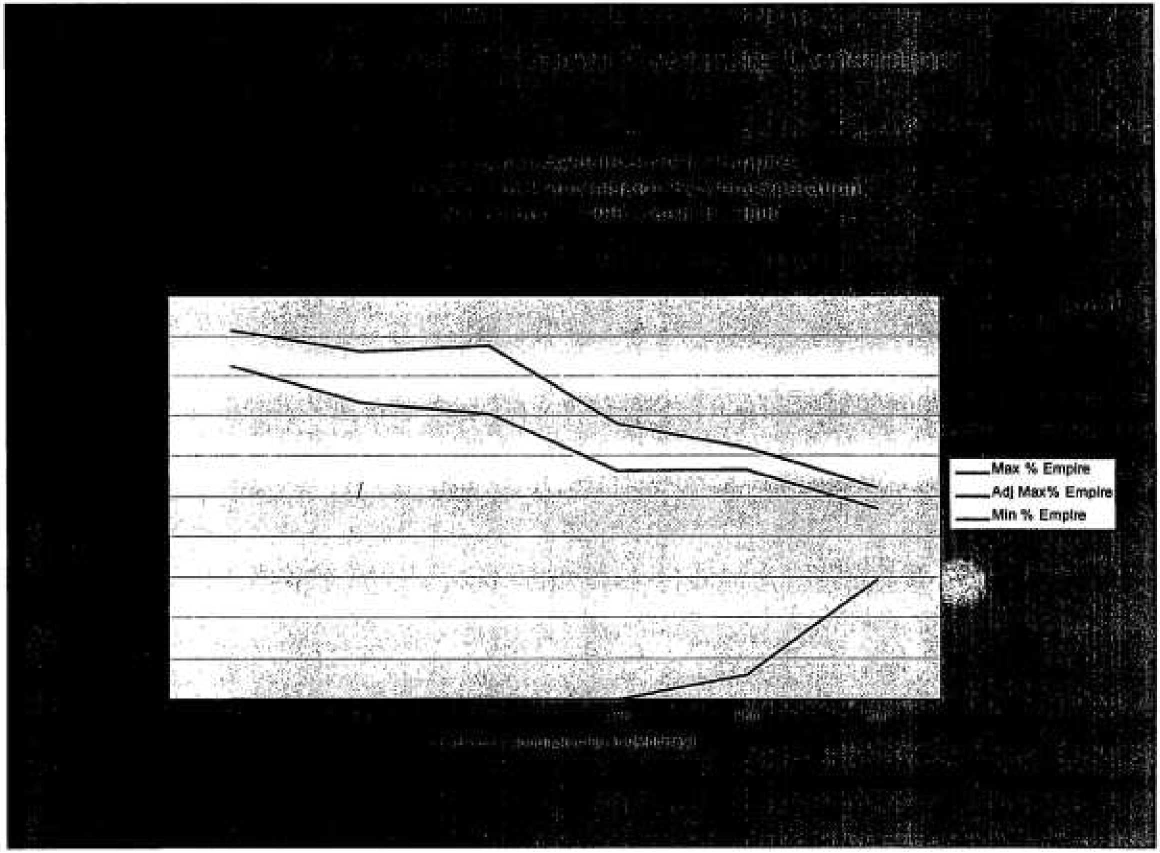
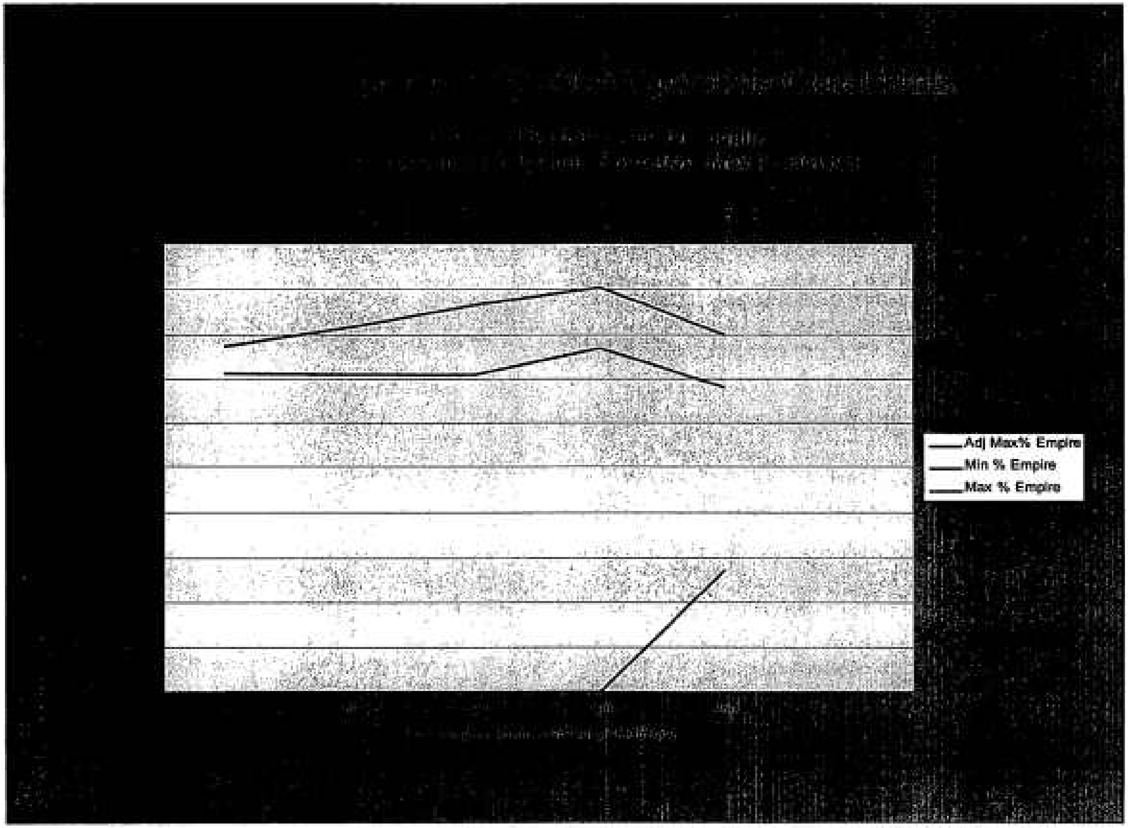

Max % Empire
Adj Max% Empire
Min % Empire


Adj Max% Empire
Min % Empire
Max % Empire

APPENDIX K

COMMUNICATIONS PROTOCOL

Communications Protocol
For
Rochester Gas & Electric Corporation
And
Gas Marketers Operating On Its System

OBJECTIVE:

The objective of this Protocol is to establish the means by which communications should take place between Rochester Gas & Electric ("RG&E") and gas marketers operating on its system ("Marketers"[1]) in order to minimize errors and effectively share all critical information.

The following general principles form the foundation for the specific elements of the Protocol described below.

- Where possible, Marketers and RG&E should verify their understanding of messages transmitted. Each party must accept the responsibility for clarifying and understanding the messages being exchanged.
- Communications should take place utilizing numerous channels, appropriate to the nature of the message being transmitted.
- Communications should be consistent within an organization (messages should not differ from one department or another) and, to the best extent practical, should be consistent over time.
- Communications should take place regularly and with a frequency appropriate to the information being transmitted.

Many of the details necessary for successful communication between RG&E and Marketers are contained in RG&E's Gas Supplier Operating Manual. This document is intended to provide a "road map" for communications between RG&E and Marketers.

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1 As used in this document, the term "Marketers" shall be understood to include gas marketers, qualified under the terms of RG&E's gas tariff to provide service to retail customers, whether unaffiliated or affiliated with RG&E, or direct customers qualified to provide gas service for their own use under RG&E's gas tariff.

I. COMMUNICATIONS CHANNELS

RG&E will provide each Marketer with a list of all key RG&E personnel with phone, pager, and cell phone numbers. Each RG&E Account Manager will leave an alternate contact name and number on his/her voice mail when unavailable.

As part of its application, each Marketer will provide the names of personnel serving in the following functions:

1. Operations staff, analysts
2. Billing contact
3. Regulatory contact
4. Credit and security contact
5. News media contact

Each Marketer will notify RG&E of personnel changes as they occur. RG&E will post the most current information it has for each Marketer on a secure portion of its web site.

II. DISPUTE RESOLUTION

Dispute resolution procedures are described in the "Common Utility Document of Business Practices," developed under the auspices of NYPSC Case 98-M-1343, and in RG&E's tariff for gas service. The following summary of the procedures must not be considered to modify or substitute for them.

To the extent that questions, problems or complaints arise between Marketers and RG&E, the party raising the dispute will first communicate with operating personnel from the opposite party in a good faith attempt to resolve the matter through informal means, such as through telephone conversations or meetings. In particular, Marketers communicate first with their RG&E Account Manager. RG&E communicates first with the appropriate Marketer contact employee as described above. If a satisfactory resolution is not forthcoming, the matter will be referred to specific personnel responsible for responding to such issues for the Marketer and RG&E. The party raising the dispute then will provide to the opposite party a written description of the dispute, together with a proposed resolution. The opposite party responds as soon as possible but in any case within 15 business days, with an agreement to adhere to the proposed resolution or with an alternative proposed resolution. If this initial exchange is inadequate to resolve the dispute, the party raising the dispute may request a meeting or meetings to further discuss the matter. The opposite party must agree to participate in such a meeting or meetings within 15 calendar days of the request. The parties may agree to the use of mediation or other alternative dispute resolution process at any time.

Disputes concerning RG&E transactions with its marketing affiliate or affiliates are handled using the above process. To the extent the dispute involves a billing issue, the disputed invoice must be paid when due, subject to refund with interest. To the extent the resolution of a dispute results in competitive benefits to a Marketer, those benefits should be made available on a prospective basis to all Marketers.

III. DAILY OPERATIONAL COMMUNICATIONS

Over the course of the operating day, operational data and information is posted and exchanged. This includes but is not limited to:

Nominations - monthly, daily, intra-day
Confirmed quantities
Scheduled quantities
Cumulative imbalances
Retail customer consumption (meter reads)

Other daily operational data exchange is described in RG&E's tariff and Gas Supplier Operating Manual.

IV. Other Operational Communications

Less frequently than daily, RG&E and Marketers will exchange information such as that set forth below:

Information provided by RG&E to Marketers:

- Meter reading schedule changes
- Billing schedule changes
- Special billing situations
- Meter exchange
- Computer system outage (planned or unplanned)
- Enrollment and transfer questions
- Rate or tax changes
- Credit limit status
- Financial security status
- Proposed procedure changes
- Gas Marketer Operating Group meeting notices
- General information of interest

Information Provided by Marketers to RG&E:

- Billing inquiries
- Enrollment and transfer questions
- Clarification of operating procedures
- Requests for assistance regarding electronic information formats
- Seasonal operating plans

In general, this type of information, or related inquiries, is communicated via an e-mail from or to the RG&E Account Manager.

V. Other Communications

As part of its ongoing communications program, RG&E will hold regular meetings -- initially, at least quarterly -- with Marketers to share information and plans and to elicit feedback on its retail access program. The communication channel for these meetings is the Gas Marketer Operating Group ("GMOG") discussed more fully in the Gas Supplier Operating Manual. Responsibility for scheduling and agenda setting for the GMOG is viewed as residing with both the Company and Marketers. The meetings are intended to address a wide range of issues that impact the relationship between RG&E and the Marketers, so wide attendance is encouraged. Agenda items will include operational updates, regulatory and legislative updates, and other items bearing on RG&E's retail access service.

To the extent RG&E and the Marketers mutually agree on the necessity for training sessions, they may take place during or in conjunction with GMOG meetings. These sessions are designed to be an orientation to RG&E's retail access programs, and to provide specialized training on specific operating issues.

VI. EMERGENCY PLANNING

In order that all Parties may respond effectively to system emergencies, RG&E will, on an annual basis, conduct simulations of system emergencies and pre-emergencies so that Marketers and RG&E can better respond to true emergencies. The timing and content of the training exercises will be discussed in the GMOG.

VII. PRE-EMERGENCIES

In order to delay, or even avoid taking emergency actions, certain activities and events must be communicated to Marketers when they occur. These events are further described in the Gas Supplier Manual.

Prior to the issuance of an OFO, RG&E will, if possible, issue an OFO Alert Notice. Marketers should respond with a report to RG&E of any action they can take to ameliorate the situation. RG&E will communicate OFO Alert Notices first via fax and then via individual telephone contacts to each Marketer.

VIII. EMERGENCIES

Emergency procedures are fully described in the Gas Supplier Manual.

In the event an OFO is required, RG&E will distribute an OFO notice via fax with follow-up telephone calls to verify receipt. Marketers are required to adjust their nominations as requested by RG&E.

In the unlikely event that an OFO does not prevent a major system emergency or outage, RG&E will communicate to affected customers and the community at large in accordance with its procedures for keeping the public informed during such an event. All information provided by RG&E to the mass media in the form of press releases, alerts, and other restoration and safety updates will be distributed to Marketers electronically or by fax immediately upon the release of such information to the media. RG&E's Account Managers will facilitate the distribution of emergency status information to Marketers, or direct their attention to relevant information posted on RG&E's web site. They will also coordinate any feedback from Marketers to RG&E on the communications process or media messages, including arranging a teleconference to discuss these issues, if requested by Marketers.

IX. POST-EMERGENCIES

Following a system gas emergency event, RG&E will conduct a debriefing session with Marketers and its public communications representatives to evaluate the communications effort. Areas identified for improvement will be assigned to a responsible person or group for follow-up action. Further post-event meetings, to the extent RG&E and Marketers mutually agree that they are necessary, will be held to review performance analyses and discuss "lessons learned." These topics may be agenda items for the GMOG, or separate meetings may be scheduled and held.

X. Retail Customer Communications

When RG&E or Marketers plan to communicate with any of their customers regarding any aspect of RG&E's gas retail access program, the party planning the communication will share its plans with other the other party with sufficient advance notice to allow for coordination of efforts.

XI. Regulatory Filings and Legislative Initiatives

In advance of making a filing with the PSC, RG&E and Marketers should strongly consider making each other aware of their intent to file, and provide information regarding the nature of the filing and the proposed filing date. To the extent that parties may be interested in jointly supporting the filing, RG&E or a particular Marketer may host meetings or teleconferences outside the normal DCOG meeting schedule to coordinate the filing.

Information on legislative initiatives should be shared and to the extent possible, coordinated lobbying efforts will be planned.

APPENDIX L

LOW INCOME ASSISTANCE PARTNERSHIP PROGRAM

Proposed Low Income Assistance Partnership (LIAP) Program

1) Overview

This program is similar to the current LIAP program agreed to in the COB II case. It consists of providing complete arrears forgiveness to the program participants who have completed, or signed up for, a weatherization program through another agency. RG&E would suspend collection activity during the term of the program, and if the customer successfully completes the program, the customer will have been current on its payments for two years and would have no arrears. The customer would receive household budget counseling in order to help him or her remain current on its payments.

2) Eligibility Requirements

In order to be eligible to participate in the program, customers must meet the following criteria:

a) The customer must be a gas or electric heating customer of RG&E;
b) The customer must have outstanding arrears with RG&E;
c) The customer must meet the income eligibility guidelines established in the Home Energy Assistance Program (HEAP);
d) The customer must have either completed, or be on a waiting list for, a weatherization program; and
e) The customer must agree to participate in household budget management training.
f) The customer must remain current on all payments (excluding arrears and late payment charges already accrued) during the program. Failure to do so will result in the customer's expulsion from the program and resumption of collection activities.

These eligibility requirements are essentially the same as for the low income program adopted (and approved by the Commission) in the settlement in RG&E's electric Competitive Opportunities proceeding, with the addition of item d). That item is seen as an administratively efficient means of ensuring that energy efficiency is improved through participation in the program. Further, this provision should be beneficial to the customer and to RG&E in that the customers who enter the program should have lower overall consumption which will give them a greater opportunity to keep current on their payments, both during and after the program. It may also provide an incentive for customers to participate in a weatherization program in order to become eligible for the LIAP program.

3) Program Components

a) Each participant in the program would be in the program for 2 years. While this is one year shorter than the current LIAP program, it will reduce the administrative burden on RG&E and reduce the overall expense of the program, with little detrimental effect.

b) RG&E will enroll 350 customers in the program during the first year of the settlement period, and another 350 customers during the second year. This number of customers is manageable with current staffing levels. However, if sufficient funding cannot be agreed upon, a lower number could be used.

c) Each customer will be put on budget billing. During the entire two years of the program, the customer's monthly bill will be the full budget amount. Customers must remain current on their monthly bill throughout the term of the program. If the customer fails to remain current during the program, it will be dropped from the program and from budget billing, and normal collection activities would resume.

d) A customer who meets all program requirements for at least one full year will receive forgiveness of 50% of its arrears balance. A customer who meets all program requirements for the full 2 years of the program will receive forgiveness of the remaining 50% of its original arrears balance. A key element to this program is that a customer successfully completing the program will have no arrears at the end, and ideally can thereafter remain current in payments for RG&E service. While the cost of the program could be reduced by forgiving less than the full arrears amount, such a feature would undercut the usefulness of the program. Under those circumstances, a customer coming out of the program would immediately go back into collection activity and have very little chance to remain current on its payments.

e) Each customer participating in the program must have completed, or be on a waiting list for, a weatherization program for its current residence through Action for a Better Community (ABC), Rural Opportunities or another agency acceptable to the Company. Customers who are not eligible for a weatherization program will be considered for enrollment in this program on a case-by-case basis. In any event, the customer will be solely responsible for compliance with the terms of the weatherization program, including implementation of any weatherization measures.

f) Each customer participating in the program will receive household financial management training. A contractor will provide this training. RG&E believes that financial counseling is essential to the customer's development of spending habits which will ensure that he or she remains current with all billings, both during and after participation in the program.

g) RG&E will suspend all collection activity during the period that the customer remains in compliance with the program criteria.

4) Program Cost

The estimated costs of the program, based on experience with the current program, are as follows:

Administration (@ $150,000/yr)	$300,000
Arrears Forgiveness (@ $2,500/cust)	$1,750,000
Avoided Costs (estimated @$125,000/yr)	($250,000)
Total Program Costs:	$1,800,000