STATE OF NEW YORK
DEPARTMENT OF PUBLIC SERVICE

16-G-0257 - PROCEEDING ON MOTION OF THE COMMISSION AS TO THE RATES, CHARGES, RULES AND REGULATIONS OF NATIONAL FUEL GAS DISTRIBUTION CORP FOR GAS SERVICE

EVIDENTIARY HEARING

Thursday, October 6, 2016
Three Empire State Plaza
3rd Floor
Albany, New York 12223-1350

A.L.J. DAKIN LECAKES
Administrative Law Judge
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16-G-0257 - NATIONAL FUEL GAS DIST. CORP - 10-6-2016

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I N D E X O F P R O C E E D I N G S

Panel (Meinl, Crahen)
Direct Examination by Mr. Nickson 1539
Cross Examination by Mr. Zimmerman 1735
Cross Examination by Mr. Mager 1773
Cross Examination by Ms. Jorgenson 1803
Cross Examination by Mr. Ford 1810

Panel (Solomon, Eck)
Direct Examination by Mr. Nickson 1824
Cross Examination by Ms. Woebbe 1914
Cross Examination by Mr. Mager 1933
Examination by the A.L.J 1941
Redirect Examination by Mr. Delvecchio 1943
Recross Examination by Ms. Woebbe 1947

Gary Marchiori
Examination by the A.L.J. 1950

Panel (Rider, Davi, Augstell, Stolicky, Ferreri, Sano, Pasinelli)
Direct Examination by Ms. Woebbe 1968
Cross Examination by Mr. Miller 1974
Cross Examination by Mr. Mager 2019
Redirect Examination by Ms. Woebbe 2050

Panel (Weeble, Miorello)
Direct Examination by Mr. Aissi 2053
Cross Examination by Mr. Mager 2108

Panel (Cej, Michalski, McAvoy)
Direct Examination by Mr. Nickson 2126
Cross Examination by Mr. Marchion 2205
Cross Examination by Mr. Mager 2248

Panel (Castana, Flaum, Semexant)
Direct Examination by Mr. Aissi 2250
Cross Examination by Mr. Mager 2277

ERIC MAINL
Direct Examination by Mr. Nickson 2288
Cross Examination by Mr. Mager 2290
Cross Examination by Mr. Ford 2298

(On the record 9:04 a.m.)

A.L.J. LECAKES: Good morning everyone. We are here on Case 16-G-0257 proceeding on the motion of the commission as to the rates, charges, rules and regulations of National Fuel Gas Distribution Corp for gas service. We are here continuing from yesterday's proceedings pursuant to a Notice of Evidentiary Hearing issued September 21st, 2016.

Yesterday we did take appearances from all parties, however, I noted for the record that Mr. Mager of Couch White, LLP was not able to make it and that I would allow him to make his own appearance this morning. Mr. Mager.

MR. MAGER: Thank you, your Honor. On behalf of Multiple Intervenors the Law Firm of Couch White, LLP, I'm Michael B. Mager.

A.L.J. LECAKES: And, Mr. Mager, do you have with you today any affidavits to get previously prefiled testimony into the record?

MR. MAGER: Yes, I do, your Honor. I have an -- an executed affidavit by Jeffrey Pollock who submitted testimony direct and rebuttal in this proceeding. And I also have 2 discs with his -- both sets of his testimony on each.

A.L.J. LECAKES: Please approach the bench.

MR. MAGER: Thank you.

A.L.J. LECAKES: Off the record.

(Off the record)

A.L.J. LECAKES: Mager has provided me with an affidavit of witness Jeffrey Pollock and that will be marked for identification as Exhibit 194.

MR. MAGER: And, your Honor, could I ask what -- what number is assigned to Jeffrey Pollock's exhibits?

A.L.J. LECAKES: We'll -- we'll get to those in a second.

MR. MAGER: Okay.

A.L.J. LECAKES: And I'm sorry, did you request that the testimony and the rebuttal be placed into the record as if orally given today?

MR. MAGER: No, but I'd like to do that now, your Honor.

A.L.J. LECAKES: Absolutely granted. So on the disc that was just provided to us by Mr. Mager, the File JP direct testimony final should be inserted and the next file JP rebuttal final should then be inserted into the transcript after that.

BEFORE THE
STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

PROCEEDING ON MOTION OF THE COMMISSION AS TO THE RATES, CHARGES, RULES AND REGULATIONS OF NATIONAL FUEL GAS DISTRIBUTION CORPORATION FOR GAS SERVICE		**CASE NO. 16-G-0257**

Direct Testimony

of

JEFFRY POLLOCK

On Behalf of

Multiple Intervenors

August 26, 2016

J. POLLOCK
INCORPORATED

BEFORE THE
STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

PROCEEDING ON MOTION OF THE COMMISSION AS TO THE RATES, CHARGES, RULES AND REGULATIONS OF NATIONAL FUEL GAS DISTRIBUTION CORPORATION FOR GAS SERVICE		**CASE NO. 16-G-0257**

TABLE OF CONTENTS

TABLE OF CONTENTS i
GLOSSARY OF ACRONYMS ii
1. INTRODUCTION, QUALIFICATIONS AND SUMMARY 1
Summary 2
2. ECOS STUDY 4
3. CLASS REVENUE ALLOCATION 8
4. SC-13 RATE DESIGN 15

GLOSSARY OF ACRONYMS

Term	Definition
ECOS	Embedded Class Cost of Service
M&R	Measurement and Regulation
MCOS	Marginal Cost of Service
MI	Multiple Intervenors
NFGD	National Fuel Gas Distribution Corporation
O&M	Operation and Maintenance
ROR	Rate of Return
RROR	Relative Rate of Return

DIRECT TESTIMONY OF JEFFRY POLLOCK

1. INTRODUCTION, QUALIFICATIONS AND SUMMARY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Jeffry Pollock; 12647 Olive Blvd., Suite 585, St. Louis, MO 63141.

Q. WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

A. I am an energy advisor and President of J. Pollock, Incorporated.

Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. I have a Bachelor of Science Degree in Electrical Engineering and a Master's Degree in Business Administration from Washington University. Since graduating in 1975, I have been engaged in a variety of consulting assignments, including energy procurement and regulatory matters in the United States and several Canadian provinces. Additional details concerning my qualifications are provided in **Exhibit ___ (JP-1)** to this testimony. A partial list of my appearances in utility rate proceedings is provided in **Exhibit ___ (JP-2)**.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A. I am testifying on behalf of Multiple Intervenors ("MI"), an association of approximately 60 large industrial, commercial and institutional energy consumers with manufacturing and other facilities located throughout New York State, including the National Fuel Gas Distribution Corporation (NFGD) service territory.

Q. WHAT ISSUES ARE YOU ADDRESSING IN YOUR TESTIMONY?

A. I am addressing:

- The embedded class cost-of-service (ECOS) Study;
- Class revenue allocation; and
- SC-13 (Transportation) rate design.

Q. ARE YOU SPONSORING ANY EXHIBITS WITH YOUR TESTIMONY?

A. Yes. I am sponsoring **Exhibit ___ (JP-1)** through **Exhibit ___ (JP-6)**. Importantly, the information presented in my testimony, and in certain of my exhibits, reflects NFGD's proposed revenue requirements and are being used here for illustrative purposes only to depict MI's recommended class revenue allocations. Nothing in my testimony or exhibits is intended to convey or imply that MI supports or accepts NFGD's proposed revenue requirements in this proceeding.

Summary

Q. PLEASE SUMMARIZE YOUR FINDINGS AND CONCLUSIONS.

A. My findings and conclusions are as follows:

ECOS Study

- In general, NFGD's ECOS Study comports with accepted industry practices.
- NFGD inadvertently misclassified the investment in FERC Account Nos. 378 (Measurement and Regulation Station Equipment), 385 (Measurement and Regulation Industrial Station Equipment) and 876/890 (Measurement and Regulation Industrial Station Equipment expense). Reclassifying Account No. 378 from customer to demand and Account Nos. 385, 876 and 890 from demand to customer results in measurable, but minimal, changes to the ECOS Study results.
- The ECOS Study results show wide disparities in class rates of return for "bundled service" ranging from -25% to +19% at current rates.

Class Revenue Allocation

- NFGD is proposing to spread most of the revenue increase equally to all service classes on present non-gas revenues. Spreading a revenue increase in this manner would move all rates away from cost. This outcome

would be contrary to the Commission's long-standing policy that supports moving rates closer to cost.

- Rates should be moved closer to cost while also recognizing gradualism to mitigate rate shock for any service classification. Accordingly, the increases allocated to the SC-1 and Cogen service classes should be *at least* 1.25 times the system average non-gas revenue increase. The remaining classes, which are providing substantially above-average returns at current rates, should receive below-average increases.
- The recommended 1.25 times constraint may be relaxed if the Company is awarded less than 50% of its requested increase.

SC-13 Rate Design

- NFGD has not provided a full marginal cost-of-service (MCOS) Study in this case. Thus, it is unclear whether the current Minimum Charges are cost-based.
- Accordingly, any delivery revenue increase allocated to the SC-13 class should be recovered equally in the Minimum Charges and Transportation Charges, instead of entirely through higher Transportation Charges as proposed by NFGD.
- The Commission should order NFGD to conduct a full MCOS Study and present the study in its next rate case.

2. ECOS STUDY

Q. HAS THE COMPANY CONDUCTED AN ECOS STUDY FOR NATURAL GAS SERVICE IN THIS PROCEEDING?

A. Yes. NFGD presented a Gas ECOS Study at current and proposed rates in its original filing.[1]

Q. HAVE YOU REVIEWED NFGD'S ECOS STUDY?

A. Yes.

Q. DOES NFGD'S ECOS STUDY COMPORT WITH ACCEPTED INDUSTRY PRACTICES?

A. Generally, yes. The study recognizes the different types of costs, as well as the different ways natural gas is delivered to customers. Further, the cost classifications and allocations generally comport with ECOS studies filed by other natural gas utilities, including utilities providing gas/delivery services to retail customers in New York.

Q. DO YOU HAVE ANY CONCERNS WITH THE ECOS STUDY?

A. Yes. NFGD inadvertently misclassified the investment in FERC Account Nos. 378 and 385. These accounts are for NFGD's investments in Measurement and Regulation (M&R) Station Equipment and M&R Industrial Station Equipment. Specifically, Account No. 378 was inadvertently classified as customer-related, while Account No. 385 was inadvertently classified as demand-related. In addition, the associated M&R

[1] Direct Testimony and Exhibits of the Cost of Service and Rate Design Panel, Exhibits ___ (COSRD-1) and ___ (COSRD-2).

Industrial Station Equipment operation and maintenance expenses (O&M) expenses (FERC Account Nos. 876 and 890) were also classified to demand.

Q. HOW SHOULD THESE ACCOUNTS HAVE BEEN CLASSIFIED?

A. NFGD stated that it should have classified Account No 378 to demand. Account Nos. 385, 876 and 890 should have been classified to customer.[2] This correction is consistent with the fact that NFGD used a demand allocator for Account No. 378 and customer allocators for Account Nos. 876 and 890. Thus, correcting these classifications will not change how these specific accounts are allocated to service classes. As explained below, it will slightly impact certain internal allocation factors that are used to allocate general and intangible plant, labor expenses and other "downstream" plant and expenses.

Q. HAVE YOU CORRECTED NFGD'S ECOS STUDY BASED ON RECLASSIFYING ACCOUNT NO. 378 FROM CUSTOMER TO DEMAND AND ACCOUNT NOS. 385, 876 AND 890 FROM DEMAND TO CUSTOMER?

A. Yes. The corrected ECOS Study at current rates is presented in **Exhibit ___ (JP-3)**. The results are summarized in the table below. For comparison, the results of NFGD's ECOS Study at current rates are also shown.

[2] NFGD's Response to MI-1-1.

Rates of Return at Current Rates Filed Versus Corrected ECOS Study				
Service Classification	Filed		Corrected	
	ROR	RROR	ROR	RROR
SC-1	2.65%	60	2.65%	60
SC-3	11.62%	263	11.68%	264
SC-13, TC 1.1	19.05%	431	19.23%	435
SC-13, TC2.0	12.34%	279	12.41%	281
SC-13, TC 3.0	13.89%	314	13.94%	315
SC-13, TC 4.0	11.58%	262	11.62%	263
SC-13, TC 4.1	6.66%	151	6.71%	152
Cogen	-25.42%	-575	-25.02%	-566

Source: Exhibit___(COSRD-2), Sch. 1, pg. 14 and Exhibit ___ (JP-3).

As the table demonstrates, the corrections have measurable, but minimal, impact on the resulting class rates of return.

Q PLEASE EXPLAIN HOW THE RESULTS OF THE CORRECTED ECOS STUDY ARE PRESENTED?

A Rate of return ("ROR") is the ratio of net operating income to the allocated rate base. Net operating income is the difference between operating revenues at current rates and allocated operating expenses. If a class presently is providing revenues sufficient to recover its cost of service (at the current system ROR), it will have a rate of return equal to or greater than the total system return.

Relative rate of return ("RROR") is the ratio of each class's ROR to the system average ROR. An RROR above 100 means that a class is providing a ROR higher than the system average, while an RROR below 100 indicates that a class is providing a below-system average ROR. Thus, a class earning a RROR of 100 would be paying its cost of service, no more and no less.

Q. WHAT DO THE ECOS STUDY RESULTS DEMONSTRATE?

A. The ECOS results demonstrate a wide disparity between class rates of return at current rates. In other words, current rates deviate substantially from cost of service. For instance, SC-1 is producing returns that only are 60% of the system average, while all of the SC-13 subclasses are producing returns well in excess of the system average, with most of those subclasses producing returns that are more than double and, in one case, over quadruple the system average. In fact, there is not a single service class that is producing an ROR close to the system average ROR. For purposes of revenue allocation, other New York utilities have relied on "dead-bands" whereby (i) classes producing RORs that are within ± 15% of the system average receive neutral or system average revenue allocations and (ii) classes producing RORs outside of those dead-bands receive allocations that are greater or less than the system average, as appropriate.

3. CLASS REVENUE ALLOCATION

Q. WHAT IS CLASS REVENUE ALLOCATION?

A. Class revenue allocation is the process of determining how any delivery revenue change approved by the Commission should be spread to each customer class served by the utility.

Q. HOW IS NFGD PROPOSING TO ALLOCATE THE PROPOSED BASE REVENUE INCREASE TO CUSTOMER CLASSES?

A. NFGD's proposed base revenue increase is shown in **Exhibit ___ (JP-4)**. As discussed in the COSRD Panel's testimony, NFGD is proposing to spread the $40.35 million increase on an equal percent basis relative to current non-gas revenues.[3]

Q. WHY IS NFGD PROPOSING AN EQUAL PERCENT INCREASE?

A. NFGD did not explain specifically why it chose to spread the $40.35 million on an equal percent basis. However, it identified several criteria for an acceptable rate design, which includes using the results of an ECOS Study as a guide.

Q. SHOULD THE ECOS STUDY BE USED ONLY AS A GUIDE IN DETERMINING HOW A REVENUE INCREASE SHOULD BE ALLOCATED TO THE VARIOUS SERVICE CLASSES?

A. No. Cost of service should be the primary criteria used to determine class revenue allocation. Thus, delivery revenues should reflect the actual cost of providing service as closely as practicable. However, regulators sometimes limit the immediate

[3] Direct Testimony of Cost of Service and Rate Design Panel at 48-49.

movement to cost based on other considerations, such as gradualism concerns. *Gradualism* is a concept that the Commission historically has used to prevent a class from receiving an overly-large rate increase. Under this practice, the movement to cost-based rates is made gradually over a period of time, rather than all at once.

In addition, rate administration and rate stability are also considerations. Rate administration means designing rates that will mitigate customer migration, thereby ensuring that the rates collect the intended revenues. Rate stability means preventing major cost shifts due to potentially significant changes in the usage characteristics of a specific customer class.

Q. WHY SHOULD THE RESULTS OF A COST-OF-SERVICE STUDY BE THE PRIMARY FACTOR IN DETERMINING HOW ANY BASE REVENUE CHANGE SHOULD BE ALLOCATED?

A. Cost-based rates will send the proper price signals to customers. The other reasons for adhering to cost-of-service principles are equity, engineering efficiency (cost-minimization), stability and conservation.

Q. WHY ARE COST-BASED RATES EQUITABLE?

A. Rates which primarily reflect cost-of-service considerations are equitable because each customer pays what it actually *costs* the utility to serve the customer (including a reasonable rate of return) – no more and no less. If rates are not based on cost, then some customers must pay part of the cost of providing service to other customers, which is inequitable.

Q. HOW DO COST-BASED RATES PROMOTE ENGINEERING EFFICIENCY?

A. With respect to engineering efficiency, when rates are designed so that customer, demand and/or energy charges are properly reflected in the rate structure, customers are provided with the proper incentive to minimize their costs, which will, in turn, minimize the costs to the utility.

Q. HOW CAN COST-BASED RATES PROVIDE STABILITY?

A. When rates are tied closely to cost, the utility's earnings are stabilized because changes in customer use patterns result in parallel changes in revenues and expenses. If rates are not based on cost, then an increase in usage by subsidized classes or a decrease in usage by classes providing subsidies would adversely affect the utility's earnings.

Q. WOULD NFGD'S PROPOSED CLASS REVENUE ALLOCATION MOVE EACH SERVICE CLASS CLOSER TO COST?

A. No. The table below summarizes the "ROR differential" of each service class at current and proposed rates. The ROR differential is the difference between each class's ROR and the system average ROR. Thus, the ROR differential measures the distance to cost. If the differential increases from current to proposed rates, it means that a service class is moving away from cost. If the differential decreases it means that a service class is moving closer to cost.

ROR and ROR Differential at Current and Proposed Rates Under NFG's ECOS Study					
Service Classification	**Current Rates**		**Proposed Rates**		**Movement to Cost**
	ROR	ROR Diff	ROR	ROR Diff	
	(1)	(2)	(3)	(4)	(5)
SC-1	2.65%	-1.77%	5.71%	-2.10%	Farther
SC-3	11.62%	7.20%	16.34%	8.53%	Farther
SC-13 TC 1.1	19.05%	14.63%	24.64%	16.83%	Farther
SC-13 TC2.0	12.34%	7.92%	17.04%	9.23%	Farther
SC-13 TC 3.0	13.89%	9.46%	19.37%	11.56%	Farther
SC-13 TC 4.0	11.58%	7.15%	17.29%	9.48%	Farther
SC-13 TC 4.1	6.66%	2.24%	11.25%	3.44%	Farther
Cogen	-25.42%	-29.84%	-25.36%	-33.17%	Farther
System Avg.	4.42%	0%	7.81%	0%	
Source	COSRD-2, Sch. 1	Col 1-4.42%	COSRD-1, Sch. 1	Col 3-7.81%	

As the table demonstrates, the ROR differential would increase for all service classes under NFGD's proposed class revenue allocation. Thus, all of the service classes would move farther away (rather than closer to) cost.

Q. WOULD THIS OUTCOME BE CONTRARY TO THE COMMISSION'S STATED POLICY, WHICH SUPPORTS THE MOVEMENT OF UTILITY RATES TOWARD ACTUAL COST?

A. Yes. The Commission has supported cost-based rates in numerous proceedings. This is evidenced by adopting revenue allocations that strive to move class RORs to within specific "tolerance bands."[4] In a recent case involving Consolidated Edison

[4] For example: *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Cooperation for Electric/Gas Service*, Case Nos. 00-E-1273 and 00-G-1274, Order Establishing Rates at 6 (Oct. 25. 2001); and *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Steam Service*, Case No. 07-S-1315, Order Establishing Rate Plan at 18 (Sept. 22, 2008).

Company of New York, Inc., the Commission articulated how cost-based rates should be achieved:

> If a specific native load customer class is generating an inadequate rate of return before any rate increase, and putting aside whether we might want to move gradually in the direction of cost to minimize harsh customer impacts, two reasonable alternatives are to: (1) shift revenue requirement first to bring up the class rate of return to where it should be, and allocate any incremental revenue requirement on an across-the-board basis; or (2) allocate an above-average increase to each class as necessary to eliminate the existing class revenue deficiency and to cover any incremental revenue requirement prospectively. The Company's approach is the first of these two alternatives and we find it is reasonable on this basis.[5]

Q. WHAT DO YOU RECOMMEND?

A. I recommend that the SC-1 and Cogen service classes receive a non-gas revenue increase that is at least 1.25 times the system average increase. The remaining service classes should receive below-average increases to move each closer to cost. My recommendation is shown in **Exhibit ___ (JP-5)** based on NFGD's claimed $40.35 million revenue deficiency.

Q. WOULD RATES MOVE CLOSER TO COST UNDER YOUR RECOMMENDED CLASS REVENUE ALLOCATION?

A. Yes. **Exhibit ___ (JP-6)** shows the ECOS Study results under the class revenue allocation shown in **Exhibit ___ (JP-5)**. The corresponding ROR and ROR differentials are summarized in the table below.

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[5] *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Electric Service* and *Petition for Approval, Pursuant to Public Service Law, Section 113(2), of a Proposed Allocation of Certain Tax Refunds between Consolidated Edison Company of New York, Inc. and Ratepayers*, Case Nos. 08-E-0539 and 08-M-0618, Order Setting Electric Rates at 205-06 (Apr. 24, 2009).

ROR and ROR Differential at Current and Recommended Rates Under NFG's ECOS Study					
Service Classification	Current Rates		Recommended Rates		Movement to Cost
	ROR	ROR Diff	ROR	ROR Diff	
	(1)	(2)	(3)	(4)	(5)
SC-1	2.65%	-1.77%	6.44%	-1.32%	Closer
SC-3	11.62%	7.20%	12.73%	4.97%	Closer
SC-13 TC 1.1	19.05%	14.63%	20.35%	12.60%	Closer
SC-13 TC2.0	12.34%	7.92%	13.44%	5.68%	Closer
SC-13 TC 3.0	13.89%	9.46%	15.16%	7.41%	Closer
SC-13 TC 4.0	11.58%	7.15%	12.91%	5.15%	Closer
SC-13 TC 4.1	6.66%	2.24%	8.93%	1.18%	Closer
Cogen	-25.42%	-29.84%	-20.36%	-28.11%	Closer
System Avg.	4.42%	0%	7.76%	0%	
Source	COSRD-2, Sch. 1	Col 1-4.42%	JP-6	Col 3-7.76%	

As previously explained, the ROR differential measures the distance to cost. Moving rates closer to cost means that the ROR differential should decrease in absolute terms. As the table demonstrates, the ROR differential would be reduced (in absolute terms) for all service classes. This means that rates are moving closer to cost.

Q. IF THE COMMISSION APPROVES A LOWER REVENUE REQUIREMENT THAN NFGD HAS PROPOSED, HOW SHOULD THIS BE REFLECTED IN THE CLASS REVENUE ALLOCATION?

A. The increase shown in **Exhibit __ (JP-5)** should be scaled back proportionally. That is, if NFGD receives 50% of its request, the amounts shown in column 2 of **Exhibit __ (JP-5)** should be reduced by 50%.

Q. WOULD YOU UTILIZE YOUR RECOMMENDED 1.25 TIMES CONSTRAINT ON REVENUE ALLOCATION TO ANY SINGLE CLASS IRRESPECTIVE OF THE REVENUE REQUIREMENT ADOPTED IN THIS RATE CASE?

A. If the final revenue requirement granted to NFGD is materially less than what was requested, the Commission should exercise its judgment in relaxing my recommended 1.25 times constraint so as to accomplish greater movement toward cost. Although my recommended revenue allocation – unlike that proposed by NFGD – moves all classes closer toward cost of service, it does not bring classes all the way to fully cost-based rates.

Constraints or caps often are appropriate mechanisms for revenue allocation purposes in order to help regulatory commissions achieve other objectives, such as gradualism discussed above. Where, as here, the utility is requesting a substantial revenue requirement increase (i.e., in excess of 15%), a constraint such as 1.25 times the system average increase helps to moderate the potential impacts on under-performing service classes while still ensuring some movement toward cost of service.

If, hypothetically, the approved revenue requirement was for a much more modest amount – say 1% or 2% - there seemingly would be little need for a 1.25 times cap and such constraint could be relaxed or possibly eliminated. In this case, if the Commission reduces NFGD's proposed revenue requirement by 50% or more, I recommend that the Commission utilize its judgment to relax, or possibly eliminate, my recommended 1.25 times constraint so as to ensure that meaningful movement of the various classes towards cost is achieved, while still adhering to principles of gradualism.

4. SC-13 RATE DESIGN

Q. HOW IS NFGD PROPOSING TO RECOVER THE INCREASE ASSIGNED TO THE VARIOUS SC-13 RATES?

A. NFGD is proposing to recover the entire delivery revenue increase through the Transportation Charges. The Minimum Charges would not be changed. The proposal to retain the Minimum Charges is seemingly at odds with NFGD's proposed class revenue allocation, which spreads the increase equally on non-gas revenues.

Q. SHOULD THE ENTIRE REVENUE INCREASE BE ASSIGNED TO THE TRANSPORTATION CHARGE?

A. No. NFGD has not provided a MCOS Study quantifying the cost-based Minimum Charges. Thus, there is no evidence to support the continued reasonableness of the existing Minimum Charges or NFGD's proposal to recover 100% of the rate increase to the SC-13 class through higher Transportation Charges. Under such circumstances, it would make more sense to increase all SC-13 charges within a subclass (i.e., the Minimum Charge and the Transportation Charge) by the same percentage.

Q. WHAT DO YOU RECOMMEND?

A. I recommend that both the Minimum Charges and Transportation Charges be increased by the same percentage. The Commission should order NFGD to conduct a full MCOS Study in its next rate case.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

BEFORE THE
STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

PROCEEDING ON MOTION OF THE COMMISSION AS TO THE RATES, CHARGES, RULES AND REGULATIONS OF NATIONAL FUEL GAS DISTRIBUTION CORPORATION FOR GAS SERVICE		**CASE NO. 16-G-0257**

Rebuttal Testimony

of

JEFFRY POLLOCK

On Behalf of

Multiple Intervenors

September 16, 2016

J. POLLOCK
INCORPORATED

BEFORE THE
STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

PROCEEDING ON MOTION OF THE COMMISSION AS TO THE RATES, CHARGES, RULES AND REGULATIONS OF NATIONAL FUEL GAS DISTRIBUTION CORPORATION FOR GAS SERVICE		**CASE NO. 16-G-0257**

TABLE OF CONTENTS

TABLE OF CONTENTS i

GLOSSARY OF ACRONYMS ii

1. INTRODUCTION, QUALIFICATIONS AND SUMMARY 1

Summary 1

2. ECOS STUDY 3

3. CLASS REVENUE ALLOCATION 18

4. SC-13 RATE DESIGN 20

5. CONCLUSION 21

GLOSSARY OF ACRONYMS

Term	Definition
Central Hudson	Central Hudson Gas & Electric Corporation
Dth	Dekatherms
GDRD	NARUC's Gas Distribution Rate Design Manual: June, 1989
GRD	NARUC's Gas Rate Design Manual: August 6, 1981
GRP	Staff's Gas Rates Panel
ECOS	Embedded Class Cost of Service
LF	Linear Foot
MCOS	Marginal Cost of Service
MI	Multiple Intervenors
NARUC	National Association of Regulatory Utility Commissioners
NFGD	National Fuel Gas Distribution Corporation
RP	UIU's Rate Panel
Staff	New York State Department of Public Service
UIU	New York State Department of State Utility Intervention Unit

REBUTTAL TESTIMONY OF JEFFRY POLLOCK

1. INTRODUCTION, QUALIFICATIONS AND SUMMARY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Jeffry Pollock; 12647 Olive Blvd., Suite 585, St. Louis, MO 63141.

Q. ARE YOU THE SAME JEFFRY POLLOCK WHO PREVIOUSLY SUBMITTED DIRECT TESTIMONY ON BEHALF OF MULTIPLE INTERVENORS ("MI")?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. I am addressing the following issues:

- Gas Embedded Class Cost-of-Service ("ECOS") Study: Recommendations by the New York State Department of Public Service ("Staff") Gas Rates Panel ("GRP") and the New York State Department of State Utility Intervention Unit ("UIU") Rate Panel ("RP");
- Class Revenue Allocation: Recommendations by the Staff GRP; and
- SC-13 Rate Design: Recommendations by the Staff GRP.

Q. DO YOU ADDRESS ALL ISSUES RAISED BY OTHER PARTIES IN THEIR DIRECT TESTIMONY?

A. No. The fact that I am not addressing all issues raised in the direct testimony of the other parties should not be interpreted as an endorsement of their recommendations or positions either by myself or MI.

Summary

Q. PLEASE SUMMARIZE YOUR FINDINGS AND CONCLUSIONS.

A. My findings and conclusions are as follows:

ECOS Study

- An ECOS Study should not use costing methods designed to help or favor a particular service class or subset thereof (thereby disadvantaging other service classes). To do so, as the UIU RP proposes, would be tantamount to using price-based costing to set rates, rather than the Commission's long-standing practice of cost-based pricing.
- Whether any competitive markets use a fixed and/or customer charge to price their products/services, as discussed by the UIU RP, is irrelevant to determining an appropriate costing and pricing for a monopoly service by a regulated natural gas delivery company.
- The UIU RP's recommendation to classify all distribution mains as demand-related is not supported by cost-causation principles, and it does not enjoy universal acceptability. In fact, it is directly contrary to the practices established in litigated rate cases in New York and the decisions of many state regulatory commissions throughout the nation.
- The UIU RP's criticisms of the zero-intercept study conducted by National Fuel Gas Distribution Corporation ("NFGD") are unwarranted and unsupported. Not only has NFGD included over 99% of its distribution mains in conducting the study, its determination that 58.56% of mains should be classified as customer-related is based on sound analysis, and the results are statistically significant.
- The Staff GRP has provided no support for its assertion that the zero-intercept method under-allocates costs to high demand service classes comprised of a few customers.

Class Revenue Allocation

- The Staff GRP appears to have ignored the results of a legitimate ECOS Study in recommending that the delivery revenue increase be spread to all classes uniformly relative to non-gas delivery revenues. This method of allocation moves all service classes away from cost, which is contrary to this Commission's long-standing practice. Accordingly, the Commission should reject Staff's proposed class revenue allocation.

SC-13 Rate Design

- The Staff GRP's proposal to increase only the SC-13 volumetric charges is not supported by a Marginal Cost of Service ("MCOS") Study. Accordingly, the Commission should reject it. The SC-13 minimum and volumetric charges should be increased by the same percentage.

2. ECOS STUDY

Q. HAVE YOU REVIEWED THE TESTIMONY THAT ADDRESSES THE ECOS STUDY FILED BY NFGD?

A. Yes. The UIU RP and, apparently, to some extent the Staff GRP, oppose the method used by NFGD for classifying distribution mains. Further, UIU, and, apparently, Staff, have issues with the decision to classify a portion of NFGD's gas distribution mains as customer-related in the ECOS Study and the percentage of such costs so classified.[1]

Q. WHAT DO YOU MEAN BY DISTRIBUTION MAINS?

A. Distribution mains represent the investment in various size pipes used to deliver natural gas to end-use customers that are booked to FERC Account No. 376.

Q. HOW DOES UIU RECOMMEND THAT DISTRIBUTION MAIN COSTS BE CLASSIFIED AND THEN ALLOCATED TO CUSTOMER CLASSES?

A. The UIU RP recommends that distribution main costs be classified entirely to demand.[2]

Q. DOES STAFF ADVANCE A SPECIFIC RECOMMENDATION ON THIS ISSUE?

A. No. The Staff GRP criticized the zero-intercept method used by NFGD to classify distribution mains. It asserted that the results of the zero-intercept methodology *may* under-allocate costs to classes that have large demands placed on the system and

[1] Direct Testimony of the UIU Rate Panel at 10, 11.

[2] *Id*. at 32.

few customers.[3] However, Staff provided no alternative proposal for classifying distribution mains. As discussed later, Staff has all but ignored the ECOS Study in this proceeding.

Q. WHAT IS THE BASIS FOR THE UIU RP'S OPPOSITION TO NFGD'S PROPOSED DISTRIBUTION MAIN COST CLASSIFICATION?

A. The UIU RP identifies four primary reasons. They are:

- The impact on smaller customers;[4]
- Incompatibility with pricing in competitive markets;[5]
- Inconsistency with cost causation;[6] and
- Not universally accepted.[7]

In addition, UIU asserts that the regression analysis underlying NFGD's zero-intercept study is flawed.[8]

Q. IS THE IMPACT OF DISTRIBUTION MAIN CLASSIFICATION IN A GAS ECOS STUDY ON SMALLER CUSTOMERS A REASON FOR REJECTING NFGD'S PROPOSAL?

A. No. The impact of a particular ECOS Study can be mitigated, where warranted, either through class revenue allocation and/or rate design. It is not a legitimate reason to

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[3] Direct Testimony of the Staff Gas Rates Panel at 74.

[4] Direct Testimony of the UIU Rate Panel at 12.

[5] *Id.* at 16.

[6] *Id.* at 13.

[7] *Id.* at 22.

[8] *Id.* at 28.

reject NFGD's proposed classification of distribution main cost. To do so would be tantamount to using price-based costing rather than the Commission's long-standing practice of setting rates using cost-based pricing. Moreover, to the greatest extent practicable, ECOS studies should reflect actual cost causation, and classification determinations should not be based on favoring smaller customers, or customers of any type.

Q. IS THERE ANYTHING INCOMPATIBLE BETWEEN THE DISTRIBUTION MAIN COST CLASSIFICATION IN A GAS ECOS STUDY AND COMPETITIVE MARKETS?

A. No. How services would be priced in a competitive market is irrelevant because there are no competitive markets for gas distribution services. Further, a competitive market implies that the provider would have no obligation to supply distribution service to all customers located in the provider's service area. However, because distribution service is a fully regulated monopoly service, it comes with the obligation to provide delivery service to all customers in the service area. Thus, competitive market pricing principles do not apply to the classification of the distribution network.

Q IS CLASSIFYING THE COSTS OF DISTRIBUTION MAINS PARTLY ON A CUSTOMER BASIS INCONSISTENT WITH COST CAUSATION, AS THE UIU RP ASSERTS?

A No, it is not. Rather, it is UIU's recommended 100% demand classification of distribution mains that is inconsistent with cost causation. For the reasons discussed below, UIU's classification is highly inappropriate and should be rejected by the

Commission.

Q WHY SHOULD A PORTION OF THE COSTS BE CLASSIFIED AS CUSTOMER-RELATED?

A. Some distribution plant investment (other than meters and services) should be classified as customer-related because the delivery system must be capable of delivering service to customers' residences or businesses (customer costs), while ensuring that the system is large enough to provide reliable service (demand costs). The ability to deliver gas to customers is completely independent of the level of the peak demand or the amount of gas consumed by customers. To the extent that this component of distribution main cost is a function of the requirement to connect the customer, regardless of the customer's size, it is both appropriate and necessary to classify a portion of the cost of those facilities to service classes based on the number of customers, and not entirely to peak demand as the UIU RP is proposing.

Q IS THE ALLOCATION OF DISTRIBUTION MAIN COSTS ON A CUSTOMER AND DEMAND BASIS CONSISTENT WITH ACCEPTED REGULATORY PRACTICE?

A Yes. The National Association of Regulatory Utility Commissioners ("NARUC") Gas Rate Design ("GRD") and Gas Distribution Rate Design ("GDRD") manuals discuss several methodologies and approaches to cost allocation. With respect to the allocation of distribution main costs, the GDRD states:

> A portion of the costs associated with the distribution system may be included as customer cost.[9]

[9] National Association of Regulatory Utility Commissioners, *Gas Distribution Rate Design* at 22 (June 1989).

It further states:

> One argument for inclusion of distribution related items in the customer cost classification is the "zero [inch] or minimum size main theory."[10]

Similarly, the GRD indicates that the cost associated with the distribution plant mains is typically functionalized on a demand and customer basis.[11]

Q ARE THE MINIMUM SIZE DISTRIBUTION SYSTEM AND ZERO INCH METHODS SIMILAR?

A Yes, in concept, they are quite similar. The minimum size approach identifies the minimum sized distribution main needed to serve customers and then classifies that portion of distribution mains as customer-related. The zero inch method (also known as zero-intercept) uses regression analysis to identify the cost of a hypothetical "zero sized" main, the cost of which is necessary to serve customers connected to the system whether or not they place any demand on the system. While there may be subtle differences between the two methods, both recognize that certain distribution main costs should be classified as customer-related and allocated based on the number of customers and not on peak demand.

Q WHAT IS THE RESULT OF FAILING TO RECOGNIZE A CUSTOMER-RELATED COMPONENT IN THE COST OF DISTRIBUTION MAINS?

A The result is a misallocation of costs that fails to allocate proper cost responsibility to the service classes. This point can be illustrated with a simple example. Assume

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[10] *Id*.

[11] National Association of Regulatory Utility Commissioners, *Gas Rate Design* at 28 (Aug. 6, 1981).

there is a single industrial customer on the NFGD system with a peak demand of 500 dekatherms ("Dth"). Further, assume that elsewhere on the system there is a neighborhood of 1,000 residential customers with an aggregated peak demand of 500 Dth. It is obvious that in order to connect all of those residential customers to the system, the Company would have to invest in far more footage of distribution mains for those customers than it would have to invest in for the one industrial customer. That extra investment in distribution mains is due solely to the number of customers on the system, not the peak demand of those customers. Thus, a portion of distribution mains expense clearly is customer-related and a 100% demand classification is inappropriate. A 100% demand classification would allocate far too little cost of distribution mains to the residential class, while non-residential sales and transportation classes would be allocated far too much cost responsibility.

Q HAS THE COMMISSION PREVIOUSLY REJECTED A PROPOSAL TO CLASSIFY ALL DISTRIBUTION MAIN COSTS TO DEMAND?

A Yes. In a Central Hudson Gas & Electric Corporation ("Central Hudson") 2008 rate case, the Commission approved the Administrative Law Judge's recommendation for the continued use of the zero-intercept method and rejection of Staff's proposal to classify distribution mains costs entirely as demand-related. The Commission noted:

> Staff proposed to reclassify gas distribution main costs for purposes of the pro forma embedded cost of service study by assigning them entirely to the demand component of rates. Currently, based on the zero-intercept methodology that Central Hudson has used since at least 1990, those costs are classified 55% to the customer component of rates and only 45% to the demand component. Because gas mains constitute 20% of the total cost of gas service, the reclassification results in a very large shift in cost responsibility from residential customers to large gas users. The RD noted that both the existing and

> proposed methodologies are deemed acceptable by NARUC with no indication that one or the other is superior. It concluded that such a large shift in cost responsibility should not be adopted without compelling evidence that it is necessary to rectify some serious inequity…We have stated repeatedly that we strive to match cost responsibility with cost causation…At the same time, as we discuss in connection with customer charges and the common cost allocation ratio, we have consistently taken a gradual approach when a sudden, full correction would create unacceptable bill impacts. That situation clearly exists here. Finally, although we find the arguments persuasive as to the assignment of a greater proportion of gas mains costs to the demand component, we are not convinced on this record that no mains costs should be classified as customer related.[12]

The Commission also rejected a 100% demand classification in Opinion No. 87-3, issued in Case Nos. 29327 and 29328. In Opinion No. 87-3, the Commission found that the utility's analysis fairly reflected the following facts:

1. Many distribution plant costs, which include capitalized labor, are incurred simply in order to deliver electricity to customer locations.

2. These costs vary noticeably with the dispersion of customer locations and with customers' decisions to take service.

3. These costs vary not at all, or very little, with the capacity of the service delivery system.[13]

I agree with these holdings because they reflect the physical realities of a gas (or electric) distribution system, as well as cost-causation principles.

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[12] *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Electric Service, et. al*., Case Nos. 08-E-0887, 08-G-0888, 09-M-0004, Order Adopting Recommended Decision with Modifications, at 46-48 (June 2009). See also, Recommended Decision at 104-107 (Apr. 2009).

[13] *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation for Electric Service and Proceeding on Motion of the Commission as to the Rates and Charges of Niagara Mohawk Power Corporation for Electric Street Lighting Service*, Case Nos. 29327 and 29328, Opinion and Order Determining Revenue Requirement and Rate Design at 238 (Mar. 13, 1987).

Q DO OTHER NEW YORK UTILITIES ALSO RECOGNIZE A CUSTOMER COMPONENT OF DISTRIBUTION MAINS?

A Yes. Niagara Mohawk Power Corporation d/b/a National Grid used the zero-intercept method in its two prior gas rate cases. In those cases, 45.5% of distribution mains were classified as customer-related costs.[14] Further, in its 2014 rate case, Central Hudson used the zero-intercept method to support classifying 35% of its distribution mains as a customer-related cost.[15]

Q. HAS A CUSTOMER COMPONENT OF DISTRIBUTION MAINS PREVIOUSLY BEEN APPROVED BY THE COMMISSION FOR NFGD?

A. Yes. In NFGD's 1995 rate case, the Consumer Protection Board and the Public Utility Law Project criticized NFGD's use of the minimum system to classify distribution mains. The Commission, citing the Recommended Decision, rejected these criticisms:

> The Judge also rejected CPB's and PULP'S attempt to impeach NFG's cost study. While they criticized the minimum distribution system concept it employed, the Judge found that it makes some sense because clearly no customer can be served without distribution facilities, and the company's approach effectively emphasized the "minimum" in the minimum distribution system.[16]

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[14] *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation for Gas Service*, Case Nos. 08-G-0609, Supplemental Testimony of Gas Rates Panel at 3 (Sep. 2, 2008); *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Niagara Mohawk Power Corporation for Electric and Gas Service*, Case Nos. 12-E-0201, 12-G-0202, Testimony and Exhibits of Gas Rates Design Panel at 18 (Apr. 2012).

[15] *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Central Hudson Gas & Electric Corporation for Gas Service, et. al*., Case No. 14-G-0319, Direct Testimony of the Cost of Service Panel at 12 (Jul. 2014).

[16] *Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of National Fuel Gas Distribution Corporation for Gas Service*, Case 93-G-0756, Opinion and Order Determining Revenue Requirement and Rate Design at 26-28 (Sep 1995).

Q. THE UIU RP CITES REGULATORY DECISIONS PRIMARILY OUTSIDE OF NEW YORK TO DEMONSTRATE THAT THE ZERO-INTERCEPT METHOD IS NOT UNIVERSALLY ACCEPTED. HOW MUCH WEIGHT SHOULD THE COMMISSION PLACE ON OTHER STATES' POLICIES?

A. The fact that recognition of a customer component of distribution mains may not be "universally accepted" provides no legitimate basis for changing what has been the long-standing policy of this Commission, which has long recognized a customer-related component of distribution mains. The Commission should accord little to no weight to the policies and practices adopted in other states. Further, as evidenced by the few number of gas rate cases cited in UIU's testimony (which includes at least one settled case), its proposed 100% demand-based classification of distribution mains similarly is not "universally accepted" for natural gas utilities.

Q. HAVE OTHER STATE COMMISSIONS SUPPORTED A CUSTOMER COMPONENT OF DISTRIBUTION MAINS?

A. Yes. About half of state regulatory commissions recognize both a customer and a demand-related component of distribution mains.[17] In particular, the state of Arkansas recently enacted Act 725 requiring the use of 2 inch mains in determining the customer-related component of distribution mains plant and related expenses. Act 725 identifies the following methodologies for determining the customer-related portion of natural gas distribution costs:

[17] *In the Matter of the Application of Northern States Power Company, d/b/a Xcel Energy, for Authority to Increase Rates for Electric Service in the State of Minnesota*, Docket No. E002/GR-15-826, Direct Testimony and Schedules of Minnesota Office of the Attorney General – Residential Utilities And Antitrust Division Witness: Ron Nelson at Direct Schedule REN-4 (Jun, 14, 2016).

- USOA numbers 374 through 376 and related depreciation, return on investment, property insurance and taxes (excluding state and federal income taxes), fixed operation and maintenance expense charged to USOA number 874: The cost of the predominant size main installed by the utility that is at least two inches in diameter.
- USOA numbers 377 through 387: A study that reflects the investments required to meter, regulate, and connect each class of customers to the gas utility's system.[18]

The Arkansas Commission must find that using these methodologies will be beneficial to economic development or the promotion of employment opportunities and will result in just and reasonable rates for all classes of customers.

Q. WHY HAVE OTHER REGULATORY COMMISSIONS RECOGNIZED THAT THERE IS A CUSTOMER COMPONENT OF DISTRIBUTION MAINS FOR COST ALLOCATION PURPOSES?

A. For example, the Connecticut Public Utilities Regulatory Authority reasoned that:

> The investment an LDC makes in mains is clearly dependent upon 1) the number of customers served and 2) the maximum coincidental demand or combined demand of all customers on the peak day. Main extensions consist of two distinct cost activities. First, there is the cost associated with the trench required to reach customers. These costs consist of digging, laying a proper bed, back-filling, tamping, and asphalt patching. The second cost relates to the size of main installed where size is determined exclusively by the coincidental peak period demand of present and future users...***In accordance with an engineering replication theory of cost responsibility, the Department believes that the classification of mains into a demand and customer component using the zero-intercept method is most appropriate***.[19] (emphasis added)

[18] Act 725 of 2015, Ark. Code Ann. § 23-4-422(b)(3).

[19] *DPUC Review of Natural Gas Companies Cost Of Service Study Methodologies*, Docket No. 99-03-28, Decision at 10-11 (Aug 9, 2000).

Q. IS UIU CORRECT THAT THE MINIMUM SIZE METHOD IS NOT BEING USED BY ANY FLORIDA ELECTRIC UTILITIES?

A. No. The Florida Public Service Commission accepted the Minimum Distribution System method for both Gulf Power and Tampa Electric.[20]

Q. THE UIU RP DISAGREES WITH THE RESULTS OF NFGD'S ZERO-INTERCEPT ANALYSIS. WHAT IS THE BASIS FOR THE DISAGREEMENT?

A. UIU asserts that because NFGD's zero-intercept cost of $8.27 per linear foot is higher than the cost of smaller diameter pipes, the zero-intercept method is inherently unreliable. UIU also asserted that the utility's regression analysis used limited data and that including more data would have resulted in a lower zero-intercept cost. Finally, UIU criticized the use of linear regression.[21]

Q. ARE THE UIU RP'S CRITICISMS VALID?

A. No. First, UIU's observation that the use of only 11 pipe sizes somehow invalidates NFGD's zero-intercept study is misplaced. The fact is that the 11 pipe sizes account for 99.5% of the linear footage and 99.3% of the costs of all distribution mains on NFGD's system. This is shown in the table below. Thus, there is no question that the data used in NFGD's zero-intercept analysis is fully representative of the utility's system and more than ample to support a sound statistical analysis. Second, including

[20] *In re: Petition for Rate Increase by Gulf Power Company*, Docket No. 130140-EI, Order Approving Stipulation and Settlement Agreement (Dec. 2013); *In re: Petition for Rate Increase by Tampa Electric Company*, Docket No. 130040-EI, Final Order Approving Stipulation and Settlement Agreement Among Tampa Electric Company, Office of Public Counsel, Florida Industrial Power Users Group, Florida Retail Federation, Federal Executive Agencies, and WCF Hospital Utility Alliance (Sept. 2013).

[21] Direct Testimony of the UIU Rate Panel at 28-30.

more pipe sizes would not improve the statistical significance of the analysis.

Distribution Mains By Size and By Average Cost Per Linear Foot[22]			
Size (Inches)	**Linear Feet (000)**	**Total Cost ($000)**	**Avg. Cost Per LF**
All Other	246.9	4,711.2	$19.08
6.625	68.8	133.1	$1.93
10.000	156.8	4,991.9	$31.83
20.000	240.4	22,358.4	$93.00
16.000	290.6	24,671.9	$84.90
1.250	707.7	10,197.9	$14.41
12.000	648.1	25,083.1	$38.70
8.000	2,532.9	62,155.6	$24.54
6.000	5,068.6	81,505.7	$16.08
3.000	10,395.1	130,809.2	$12.58
4.000	10,780.2	123,656.9	$11.47
2.000	19,243.6	221,451.1	$11.51
Total Run 4	50,132.8	707,014.8	$14.10
Total Mains	50,379.7	711,726.0	$14.13
Run 4 as a % of Total Mains	99.5%	99.3%	99.8%

Q. PLEASE EXPLAIN.

A. The UIU RP refers to Run 2, which had a higher correlation coefficient than the analysis used by NFGD, which was Run 4. However, statistical significance is not measured using a correlation coefficient. It is measured by the t-statistic. The t-statistic is a measure of the significance of the independent variable's (in this case the radius of the pipe) coefficient that is calculated using the regression model. If the t-statistic is greater than 1.96, it is considered statistically significant at a 95%

[22] NFDG's Response to DPS-33, Workpaper-Mains_Customers_Demand.xlxs.

confidence level. A value less than 1.96 would decrease the confidence in the coefficient.

Q. WERE THE RESULTS OF NFGD'S ANALYSIS STATISTICALLY SIGNIFICANT?

A Yes. The t-statistic for Run 4 (NFGD's analysis) was 2.43.

Q. WOULD INCLUDING MORE PIPE SIZES AS UIU ASSERTS MAKE THE ANALYSIS MORE STATISTICALLY SIGNIFICANT?

A. No. The UIU RP asserts that NFGD should have used Run 2. However, the t-statistic for Run 2 is only 0.90. Not only is this much lower than the t-statistic for NFGD's analysis (of 2.43), it is also below the threshold for determining statistical significance. In other words, the Run 2 analysis is statistically insignificant. NFGD's zero-intercept analysis is not only statistically significant, it clearly demonstrates greater confidence that the coefficient for the radius of the pipe is an accurate prediction of the correlation between the radius of the pipe and the cost per foot of the pipe.

Q. IS IT APPROPRIATE TO USE A LINEAR REGRESSION WHEN PERFORMING A ZERO-INTERCEPT STUDY?

A. Yes. The GRD provides an example of how to calculate the customer portion of main cost using the zero-intercept method. The example uses a linear regression analysis to estimate the customer component of the cost.[23]

[23] GRD at 40.

Q. IS THE ESTIMATED COST OF A ZERO-INCH PIPE REALISTIC?

A. Yes. The estimated cost per foot of pipe based on NFGD's analysis is $8.27 per linear foot (LF). As demonstrated in the above table, NFGD has installed over 19 million linear feet of 2 inch mains. This represents 38% of the Company's installed pipe. Thus, 2 inch mains are the predominant size pipe utilized by NFGD. The average cost for a 2 inch main is $11.51/LF. This demonstrates that the zero-intercept cost is not unreasonable.

Q. UIU STATES THAT SINCE THE COST OF 1" PIPE IS LESS THAN THE ZERO-INTERCEPT COST IT SHOWS THAT NFGD'S ANALYSIS IS CONTRADICTORY. DO YOU AGREE?

A No. NFGD has approximately 24,000 linear feet (less than 5 miles) of 1 inch pipe with an average cost of $2.56/LF. However, it has nearly 30 times more 1.25 inch pipe that has an average cost of $14.41/LF. Thus, a zero-intercept cost of $8.27/LF is not unreasonable.

Q. IF NFGD HAD CONDUCTED A MINIMUM SIZE ANALYSIS OF ITS DISTRIBUTION MAINS, WHAT PORTION OF DISTRIBUTION MAINS WOULD BE CLASSIFIED AS A CUSTOMER-RELATED COST?

A. The predominant size main is a 2 inch pipe. The average cost of 2 inch pipe mains is $11.51/LF. The average cost of distribution mains is $14.13/LF. Thus, the minimum size method would classify 81% ($11.51÷$14.13) of distribution mains as customer-related. When viewed in this context, NFGD's zero-intercept analysis is reasonable and, arguably, understated as opposed to overstated.

Q. PLEASE SUMMARIZE YOUR REBUTTAL TO THE UIU RP.

A. None of the four reasons suggested by the UIU RP support rejecting NFGD's proposed distribution main cost classification. Classifying a portion of the distribution mains as a customer-related cost is not only consistent with cost causation, it appropriately recognizes that utilities incur minimum costs to provide the capability necessary for a gas delivery system to deliver natural gas to end-use customers. It is also consistent with this Commission's long-standing policy, as determined in litigated cases, and it is accepted by many other regulatory commissions. Accordingly, the Commission should reject the UIU RP's recommendation.

3. CLASS REVENUE ALLOCATION

Q. DO PARTIES OTHER THAN NFGD AND MULTIPLE INTERVENORS ADDRESS CLASS REVENUE ALLOCATION?

A. Yes. The Staff GRP addresses class revenue allocation.

Q. WHAT DID STAFF RECOMMEND?

A. Staff accepted NFGD's proposed class revenue allocation.[24]

Q. IS STAFF'S RECOMMENDATION BASED ON THE RESULTS OF AN ECOS STUDY?

A. No. The Staff GRP states:

> The Company did not propose to shift revenues to correct for return imbalances as shown in the COS study. We, therefore, believe the methodology is reasonable.

Thus, Staff seemingly ignored the results of NFGD's ECOS Study in its recommended class revenue allocation.

Q. WHY DID STAFF IGNORE NFGD'S ECOS STUDY?

A. As previously stated, the Staff GRP asserted that NFGD's zero-intercept study may understate the costs allocated to certain service classes. Significantly, however, Staff did not present any quantitative analysis or provide an alternative ECOS Study to support its proposed class revenue allocation.

[24] Direct Testimony of the Staff Gas Rates Panel at 75.

Q. SHOULD THE STAFF GRP'S PROPOSED CLASS REVENUE ALLOCATION BE ADOPTED?

A. No. As I explained in my Direct Testimony:

- NFGD did not explain specifically why it chose to spread the $40.35 million on an equal percent basis, despite citing the use of an ECOS Study as a guide.
- An equal percent increase would move all service classes away from cost, contrary to this Commission's long-standing practice of moving classes toward cost.

Q. SHOULD THERE CONTINUE TO BE MEANINGFUL MOVEMENT TOWARD COST-BASED RATES NOTWITHSTANDING THE REDUCED REVENUE INCREASE RECOMMENDED BY STAFF?

A. Yes. Staff's revenue requirement recommendation, if adopted, provides an ideal environment for moving rates closer to cost without causing rate shock. If the Commission approves Staff's revenue requirement recommendation, it should relax the traditional gradualism constraints even if it means, as in this instance, reducing delivery rates to the non-residential service classes, all of which are currently providing revenues substantially in excess of their allocated costs.

4. SC-13 RATE DESIGN

Q. HAVE ANY PARTIES OTHER THAN NFGD AND MULTIPLE INTERVENORS ADDRESSED THE DESIGN OF THE RATES APPLICABLE TO THE SC-13 CLASS?

A. Yes. The Staff GRP has addressed the SC-13 class rate design.

Q. WHAT IS THE STAFF GRP RECOMMENDING?

A. The Staff GRP is recommending, consistent with NFGD's proposal, that the entire revenue change to the SC-13 class be recovered in the volumetric charges.[25] Staff does not appear to offer any independent reasons or justifications for its position on this issue.

Q. DO YOU AGREE WITH STAFF'S RECOMMENDATION?

A. No. As discussed in my Direct Testimony:

- NFGD has not provided a MCOS Study quantifying the cost-based Minimum Charges.
- There is no evidence to support the continued reasonableness of the existing Minimum Charges or NFGD's proposal to recover 100% of the rate increase to the SC-13 class through higher Transportation Charges.

Q. SHOULD THE STAFF GRP'S RECOMMENDED SC-13 RATE DESIGN BE ADOPTED?

A. No. Under these circumstances, it would make more sense to increase all SC-13 charges (i.e., the Minimum Charge and the Transportation Charge) by the same percentage.

[25] *Id.* at 86.

5. CONCLUSION

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. The Commission should adopt the following recommendations:

- Adopt NFGD's ECOS Study, with the minor corrections to reclassify FERC Account No. 378 (Measurement and Regulation Station Equipment) from customer to demand, and reclassify Account No. 385 (Measurement and Regulation Industrial Station Equipment) and Account Nos. 876/890 (Measurement and Regulation Industrial Station Equipment expense) from demand to customer.
- Reject the UIU RP's recommendation to classify all distribution mains to demand.
- Reject NFGD and Staff's proposed equal percentage increase in non-gas delivery revenues, which would result in moving all service classes farther away from cost, contrary to this Commission's long-standing practice of relying on the results of ECOS studies for cost allocation purposes and moving rates closer to cost.
- Move all service classes closer to cost subject to gradualism constraints normally used by the Commission to prevent rate shock (*i.e.,* increase not exceed 1.25 times the system average non-gas delivery revenues).
- Relax the gradualism constraints if NFGD receives only a small fraction of its requested increase.
- Reject NFGD and Staff's proposals to retain the Minimum Charge and apply any increase allocated to the SC-13 class to the volumetric charges.
- Change all SC-13 charges by the same percentage as the change in non-gas delivery revenues allocated to the SC-13 class.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

Mr. Mager, did Mr. Pollock have any exhibits attached to his testimony?

MR. MAGER: Yes, he did, your Honor. He had Exhibits JP 1 through JP 6. 6 exhibits.

A.L.J. LECAKES: Okay. Starting with JP 1 we'll mark that for identification as 195. JP 2 we'll mark as Exhibit 196. JP 3 Exhibit 197, JP 4 Exhibit 198. JP 5 Exhibit 199 and JP 6 Exhibit 200. Anything further from MI at this point?

MR. MAGER: No, thank you, your Honor.

A.L.J. LECAKES: Okay. Pursuant to a schedule that I circulated before the part -- before the hearing for the order of witnesses I have listed as the NFG Cost of Service Rate Design Panel. Company could you please call your witnesses?

MR. DELVECCHIO: The company calls Eric H. Meinl and Evan M. Crahen.

A.L.J. LECAKES: Mr. Crahen and Mr. Meinl, could you please state your names for the record and your business addresses?

MR. MEINL: Eric H. Meinl, 6363 Main Street, Williamsville, New York.

MR. CRAHEN: Evan M. Crahen, 6363 Main

Street, Williamsville, New York.

A.L.J. LECAKES: Could you please both stand and raise your right hands? Do you swear or affirm today that the testimony you're about to give is the whole truth?

MR. MEINL: Yes.

MR. CRAHEN: Yes.

ERIC MEINL; Sworn

EVAN CRAHEN; Sworn

A.L.J. LECAKES: Yes, please be seated. Counsel for the company please direct your witnesses to get their testimony and exhibits into the record.

DIRECT EXAMINATION

BY MR. NICKSON:

Q. Panel, do you have in front of you a document entitled direct testimony of the cost of service and rate design panel consisting of 79 pages of questions and answers?

A. (Panel) Yes.

Q. Was that document prepared by you and under your supervision?

A. (Crahen) Yes.

Q. And do you have any changes or

1 Q. Please state the names of the members of the Cost of
2 Service and Rate Design Panel ("Panel").
3 A. We are Eric H. Meinl and Evan M. Crahen.
4 Q. Mr. Meinl, please state your business address.
5 A. My business address is 6363 Main Street,
6 Williamsville, New York 14221.
7 Q. By whom are you employed and in what capacity?
8 A. I am employed by National Fuel Gas Distribution
9 Corporation ("Distribution" or the "Company") as
10 General Manager in the Rates and Regulatory Affairs
11 Department.
12 Q. Have you provided your educational and professional
13 experience elsewhere in this proceeding?
14 A. Yes, I have provided this information in the Direct
15 Testimony of Eric H. Meinl in this proceeding.
16 Q. Mr. Crahen, please state your name and business
17 address.
18 A. My business address is 6363 Main Street,
19 Williamsville, New York 14221.
20 Q. By whom are you employed and in what capacity?
21 A. I am employed by Distribution as a Regulatory
22 Analyst II in the Rates and Regulatory Affairs

1 Department.
2 Q. Have you provided your educational and professional
3 experience elsewhere in this proceeding?
4 A. Yes, I have provided this information in the Direct
5 Testimony of Evan M. Crahen in this proceeding.
6 Q. What is the purpose of the Panel's direct testimony?
7 A. The purpose of this panel's direct testimony is to
8 describe: (1) the cost of service study, which
9 complies with the New York State Public Service
10 Commission's ("Commission") Order issued on August
11 25, 2004, in the statewide unbundling proceeding
12 (Case 00-M-0504); (2) marginal transmission,
13 distribution and customer costs; and (3) the
14 proposed rate design and tariff changes. It should
15 be noted that the cost of service study has been
16 completed to comply with the August 25, 2004
17 Commission Order and does not represent an
18 endorsement of the Order's methods.
19 **Cost of Service - Overview**
20 Q. Please summarize the layout of the Exhibits and
21 Workpapers related to the embedded cost of service
22 study you are presenting in this proceeding.

A. The embedded cost of service study presented in this proceeding is voluminous and relies on a number of special studies and related Workpapers. For the convenience of the parties reviewing the study, an overall summary of the layout of Exhibits and supporting Workpapers is provided on pages 4 through 7.

	Total Company "Bundled"	Delivery	Natural Gas Supply (NGS)	Billing and Payment (B&P) Processing
Exhibits				
Total Company Proposed Rates Service Class Allocation	Exhibit ____ (COSRD-1) Schedule 1	Exhibit ____ (COSRD-1) Schedule 2	Exhibit ____ (COSRD-1) Schedule 3	Exhibit ____ (COSRD-1) Schedule 4
Total Company Proposed Rates Customer Cost Analysis	Exhibit ____ (COSRD-1) Schedule 5			
Total Company Current Rates Service Class Allocation	Exhibit ____ (COSRD-2) Schedule 1	Exhibit ____ (COSRD-2) Schedule 2	Exhibit ____ (COSRD-2) Schedule 3	Exhibit ____ (COSRD-2) Schedule 4
Total Company Current Rates Service Class Allocation Factors	Exhibit ____ (COSRD-2) Schedule 5			
Total Company Class Allocation Factor Report	Exhibit ____ (COSRD-2) Schedule 6			
Total Company Current Rates Classification Allocation	Exhibit ____ (COSRD-3) Schedule 1			
Total Company Current Rates Classification Allocation Factor Report	Exhibit ____ (COSRD-3) Schedule 2			

	Total Company "Bundled"	Delivery	Natural Gas Supply (NGS)	Billing and Payment (B&P) Processing
Workpapers - Studies				
Supply Function Proposed Rates Service Class Allocation	Workpaper COSRD-1 Schedule 1 Supply Bundled	Workpaper COSRD-1 Schedule 2 Supply Delivery	Workpaper COSRD-1 Schedule 3 Supply NGS	Workpaper COSRD-1 Schedule 4 Supply B & P
Storage Function Proposed Rates Service Class Allocation	Workpaper COSRD-1 Schedule 1 Storage Bundled	Workpaper COSRD-1 Schedule 2 Storage Delivery	Workpaper COSRD-1 Schedule 3 Storage NGS	Workpaper COSRD-1 Schedule 4 Storage B & P
Transmission Function Proposed Rates Service Class Allocation	Workpaper COSRD-1 Schedule 1 Transmission Bundled	Workpaper COSRD-1 Schedule 2 Transmission Delivery	Workpaper COSRD-1 Schedule 3 Transmission NGS	Workpaper COSRD-1 Schedule 4 Transmission B & P
Distribution Function Proposed Rates Service Class Allocation	Workpaper COSRD-1 Schedule 1 Distribution Bundled	Workpaper COSRD-1 Schedule 2 Distribution Delivery	Workpaper COSRD-1 Schedule 3 Distribution NGS	Workpaper COSRD-1 Schedule 4 Distribution B & P
B & P Function Proposed Rates Service Class Allocation	Workpaper COSRD-1 Schedule 1 B & P Bundled	Workpaper COSRD-1 Schedule 2 B & P Delivery	Workpaper COSRD-1 Schedule 3 B & P NGS	Workpaper COSRD-1 Schedule 4 B & P B & P
Comp. ES Function Proposed Rates Service Class Allocation	Workpaper COSRD-1 Schedule 1 Comp. ES Bundled	Workpaper COSRD-1 Schedule 2 Comp. ES Delivery	Workpaper COSRD-1 Schedule 3 Comp. ES NGS	Workpaper COSRD-1 Schedule 4 Comp. ES B&P
Clearing Function Proposed Rates Service Class Allocation	Workpaper COSRD-1 Schedule 1 Clearing Bundled	Workpaper COSRD-1 Schedule 2 Clearing Delivery	Workpaper COSRD-1 Schedule 3 Clearing NGS	Workpaper COSRD-1 Schedule 4 Clearing B&P

	Total Company "Bundled"
Service Class Allocation Factor Report Current Rates All Functions	Workpaper COSRD-2 Schedule 6
Supply Function Current Rates Classification Allocations	Workpaper Exhibit ___ (COSRD-3) Schedule 1 Supply
Storage Function Current Rates Classification Allocations	Workpaper Exhibit ___ (COSRD-3) Schedule 1 Storage
Transmission Function Current Rates Classification Allocations	Workpaper Exhibit ___ (COSRD-3) Schedule 1 Transmission
Distribution Function Current Rates Classification Allocation	Workpaper Exhibit ___ (COSRD-3) Schedule 1 Distribution
B & P Function Current Rates Classification Allocation	Workpaper Exhibit ___ (COSRD-3) Schedule 1 B & P
Comp. ES Function Current Rates Classification Allocations	Workpaper Exhibit ___ (COSRD-3) Schedule 1 Comp. ES
Clearing Function Current Rates Classification Allocation	Workpaper Exhibit ___ (COSRD-3) Schedule 1 Clearing

Workpapers Special Allocation Studies into Functions	
Plant Allocation - General Plant Reserve Allocation - General Plant Depreciation Expense Allocation - General Plant	Workpaper General Plant Allocation
Structures Allocation	Workpaper Structures Allocation
All Labor Allocation	Workpaper All Labor Allocation
Consumer Services Allocation	Workpaper Consumer Services
A&G Allocator	Workpaper A&G Allocation
Workpapers Special Allocation Studies into Classification	
Mains Study Customer/Demand Allocation	Workpaper Mains Customer/Demand
Workpapers Special Allocation Studies into Service Classes	
Cogeneration Allocation	Workpaper Cogeneration Allocation
Main Allocation Study <4″ / >=4″ Allocation	Workpaper Mains 4″ Allocation
Service Line Service Class Allocation	Workpaper Services Allocation
Meter Investment Service Class Allocation	Workpaper Meters Allocation
Industrial M&R Service Class Allocation	Workpaper Industrial M&R Allocation
Uncollectibles Service Class Allocation	Workpaper Uncollectibles Allocation
Customer Service Allocation	Workpaper Customer Service Allocation
Sales Promotion Allocation	Workpaper Sales Promotion

1 Q. Please state the purpose of a fully-allocated, cost
2 of service study.
3 A. A fully-allocated, cost of service study assigns to
4 each revenue or customer class its proportionate
5 share of the Company's total cost of service.
6 Fully-allocated, cost of service study results can
7 be utilized to determine the relative cost of
8 service for each class of customers and to help
9 determine the individual class revenue requirements.
10 Fully-allocated, cost of service studies can also be
11 used to determine the appropriate rate structures of
12 individual customer classes.
13 Q. Please describe the general procedure employed in
14 performing the fully-allocated, cost of service
15 study.
16 A. Prior to the unbundling proceeding (Case 00-M-0504),
17 the general procedure employed in performing fully-
18 allocated, cost-of-service studies consisted of four
19 separate steps. The four separate steps were: (1)
20 functionalization of plant and operating expenses;
21 (2) classification of costs; (3) derivation of

allocation methods; and (4) the actual allocations of plant and expense items to the customer classes.

The unbundling proceeding added a fifth step that separates costs further into specific "Buckets" ("Buckets" or "Functions"), and a sixth step that assigns each functional cost to the unbundled services. For Distribution, these unbundled services are Delivery, Natural Gas Supply ("NGS") and Billing and Payment Processing ("Billing and Payment" or "B&P").

The first step, functionalization of plant and operating expenses, identifies and separates plant and cost elements into specific categories based on the various characteristics of utility operations. For Distribution, the functional cost categories for plant include natural gas production, transmission, distribution, general, and intangible plant. Operating expenses are functionalized as natural gas production, gas supply, transmission, distribution, customer accounts, customer service, and administrative and general. The Federal Energy Regulatory Commission ("FERC") Uniform System of

1 Accounts defines the standards for the
2 functionalization of plant and operating expenses.
3 The second step of the general procedure used
4 in performing fully-allocated, cost-of-service
5 studies is the classification of costs. The
6 classification of costs further separates the
7 functionalized plant and operating expenses into
8 four basic components. The four basic components of
9 cost classification are: (1) demand or capacity-
10 related, (2) commodity or energy-related, (3)
11 customer-related, and (4) revenue-related. Demand
12 or capacity costs are related to plant and expenses
13 incurred due to a customer's peak load requirement.
14 The number of customers or the amount of annual
15 usage does not directly impact the level of demand
16 costs. Commodity or energy costs are incurred in
17 proportion to the customer's volumetric gas
18 consumption. Neither demand-related plant and
19 expenses nor customer-related plant and expenses
20 impact the level of commodity costs. Costs
21 associated with providing service to a customer are
22 defined as customer-related costs. Costs associated

1 with the customer's total annual use of gas, or the
2 customer's total peak demand for gas, are not
3 included in customer-related costs. Revenue-related
4 costs are costs which vary by the amount of revenue
5 received by the utility. Each of the previously
6 functionalized costs is further identified as
7 related to one or more of these cost classes.
8 The third step of the general procedure used in
9 performing fully-allocated, cost-of-service studies
10 is the derivation of allocation methods. The
11 essential element in deriving reasonable cost-of-
12 service allocation methods is the establishment of
13 operating relationships between customer gas service
14 requirements and the cost incurred by Distribution
15 in meeting these requirements. These relationships
16 are established by analyzing the gas system design
17 and operations, Distribution's accounting records,
18 and load data and sales revenues by revenue
19 classifications. From the results of the analyses,
20 methods of direct assignment and common plant
21 allocation are chosen for all plant and expense
22 elements. Direct assignments of plant and expenses

to particular customers or classes of customers are made on the basis of special studies wherever the necessary data is available. These assignments are developed by detailed analyses of maps and records, work order descriptions, property records and/or customer accounting records. Within time and budgetary constraints, the greater the magnitude of cost responsibility based upon direct assignments, the less reliance need be placed on common plant allocation methodologies associated with joint-use plant. Common or joint-use plant allocation methodologies are chosen by analyzing the distinguishing operating characteristics of each customer class. These operating characteristics include annual gas consumption, peak period usage, load factor, and the numbers of customers in a particular class.

The fourth step of the general procedure used in performing fully-allocated, cost-of-service studies is the actual allocation of plant items and expense items to the customer classes. Actual allocation entails the application of previously

1 chosen common allocation methodologies to the
2 functionalized and classified plant and expenses
3 that have not already been directly assigned.
4 Q. Please provide a general description of the fifth
5 step where costs are separated into specific
6 Buckets, as required by the Commission in Case
7 00-M-0504.
8 A. Using the books and records of the Company, the
9 traditional cost of service study was separated into
10 the "Buckets" outlined in Appendix A of the November
11 9, 2001 Order in Case 00-M-0504. The Buckets are:
12 (1) Supply Function;
13 (2) Storage Function;
14 (3) Transmission Function;
15 (4) Distribution Function;
16 (5) Billing and Payment Processing Function;
17 (6) Competitive Energy Services Function; and
18 (7) Clearing Accounts Function (including
19 Customer Care).
20 Q. Please describe the Supply Function.
21 A. The Supply Function includes all direct production
22 oriented plant and expenses. Also included are

1 indirect costs for general plant and operations and
2 maintenance ("O&M") expenses resulting from
3 allocation studies. These studies will be described
4 in more detail later in this testimony.
5 For Distribution, costs associated with
6 Production Plant (both plant and O&M) are more
7 closely aligned with the Transmission Function in
8 that they are for the most part small gathering-type
9 plant attached to local production wells, and not
10 part of the system that provides for Natural Gas
11 Supply Service. In compliance with the November 9,
12 2001 Order in Case 00-M-0504, Purchase Gas Expense
13 (Account 401999) and Other Gas Supply Expense
14 (Accounts 807.1 - 813) have been allocated between
15 the Supply and Distribution Function. Uncollectible
16 Accounts (Account 904) follows operating revenues,
17 as prescribed in the Order.
18 Q. Please describe the Storage Function.
19 A. The Storage Function includes all direct storage-
20 oriented plant, which for Distribution is Gas
21 Storage Inventory. In Distribution's last base rate
22 case (Case 07-G-0141), storage inventory was removed

1 from rate base, and treated as an interest expense
2 to be recovered through the merchant function
3 charge. Therefore, storage inventory has been
4 excluded from this study. Distribution does not
5 have any storage O&M expenses and no indirect
6 allocations to the Storage Function.
7 Q. Please describe the Transmission Function.
8 A. The Transmission Function includes all direct
9 transmission-oriented plant and expenses. These
10 include plant accounts 365 through 369 and O&M
11 expenses in Control Accounts 401500 (Operating
12 Expense - Transmission) and 402500 (Maintenance
13 Expense - Transmission). Also included are indirect
14 costs for general plant and O&M expenses resulting
15 from the allocation studies, as well as all
16 Production Plant costs, as described above.
17 Q. Please describe the Distribution Function.
18 A. The Distribution Function includes all direct
19 distribution-oriented plant and expenses. These
20 include plant accounts 374 through 387 and all O&M
21 expenses in Control Accounts 401600 (Operating
22 Expense - Distribution) and 402600 (Maintenance

1 Expense - Distribution). Also included are direct
2 O&M costs for meter reading in Control Account
3 401700 (Operating Customer Account Expense) and
4 Utility Energy Services costs in Control Accounts
5 401800 (Operating Customer Service and Information
6 Expense) and 401850 (Operating Sales Expense).
7 Indirect costs for general plant and O&M expenses
8 resulting from the allocation studies were also
9 included. As described above, the Distribution
10 Function includes a portion of Purchase Gas Expense
11 (Account 401999), Other Gas Supply Expense (Accounts
12 807.1 - 813) and the Uncollectible Account (Account
13 904).
14 Q. Please describe the Billing and Payment Processing
15 Function.
16 A. The Billing and Payment Processing Function does not
17 include any direct plant accounts or direct O&M
18 expenses. The Billing and Payment Processing
19 Function is embedded within Control Account 401700
20 (Operating Customer Account Expense) and was derived
21 via the allocation studies. General Plant accounts
22 and O&M expenses (e.g., Uncollectible Accounts and

1 Administrative and General) were also allocated to
2 the Billing and Payment Processing Function.
3 Q. Please describe the Competitive Energy Services
4 Function.
5 A. Distribution does not have a Competitive Energy
6 Services function, and as a result, the Company has
7 not allocated plant accounts or O&M expenses to this
8 function.
9 Q. Please describe the Clearing Account Function.
10 A. Appendix A of the November 9, 2001 Order in Case 00-
11 M-0504 ("November 9, 2001 Unbundling Order")
12 describes the Clearing Account Function as
13 Uncollectibles (supply and non-supply) and Customer
14 Care. The Clearing Account Function, as defined in
15 the November 9, 2001 Unbundling Order, is embedded
16 within Control Account 401700 (Operating Customer
17 Accounts Expense) and was derived via the allocation
18 studies. General Plant accounts and O&M expenses
19 (including Administrative and General) were also
20 allocated to the Clearing Account Function.
21 Uncollectibles were not included in the Clearing
22 Account Function, but were included in the Functions

that had operating revenues (specifically the Supply Function, Distribution Function and the Billing and Payment Processing Function). This was completed to allow for the allocation of costs based on revenues.

Q. Please describe the sixth step in the embedded cost of service study.

A. The sixth step assigns each Function by Service Class to the unbundled service of Delivery, Natural Gas Supply, or Billing and Payment Processing. The summation of the three unbundled services is the Total Cost for the Company, which is titled Total Company "Bundled Service." The assignment of each function to these unbundled services was completed in accordance with the following matrix:

Function	Delivery Service	Natural Gas Supply Service	Billing and Payment Processing Service
Supply Function		100.00%	
Storage Function		100.00%	
Transmission Function	100.00%		
Distribution Function	100.00%		
Billing and Payment Processing Function			100.00%
Competitive Energy Services Function	100.00%		
Clearing Accounts Function	52.72%		47.28%

Cost of Service - Classification

Q. Please describe the classification step in the cost of service study.

A. The classification step in the cost of service study classifies the costs into a Demand component, Customer component, Commodity component, or a Revenue component. Demand or capacity costs are

related to plant and expenses incurred to serve a customer's peak load requirement. Annual usage does not directly affect the level of demand costs. Commodity costs are incurred in proportion to the customer's volumetric consumption.

The classification factors outlined in Exhibit___(COSRD-3), Schedule 1, Column S, were used throughout the seven Functions. For example, General Plant Office Equipment - Furniture (Account 391.1) was classified as 26.08% Demand and 73.92% Customer, regardless of whether the plant was in the Distribution Function or the Supply Function. Distribution Mains (Account 376) were assigned 58.56% Customer and 41.44% Demand based on the Mains study described below. General Plant Structures (Account 390) and the associated Land (Account 389) were based on the Structures study described below. Office Equipment - Furniture, General and Computers (Account 391.1, 391.2 and 391.3, respectively) and Communication Equipment (Account 397) were based on the All Labor study described below.

Referencing Exhibit___(COSRD-3), Schedule 1,

Page 1, Gas Plant in Service totaled $1,491,012,000. $434,410,422 of this total is Demand related and $1,056,601,578 of this total is Customer related. There is no Commodity or Revenue related Gas Plant in Service. The classification factors used for Gas Plant in Service were also used for the Accumulated Reserve for Depreciation (Exhibit___(COSRD-3), Schedule 1, Page 2) and Depreciation Expense (Exhibit___(COSRD-3), Schedule 1, Page 3).

Referencing Exhibit___(COSRD-3), Schedule 1, Page 4, the deferred Commission Assessment was classified based on the classification of the O&M Regulatory Expense (Account 928), which is outlined on Page 8 of Exhibit___(COSRD-3). Schedule 1, Page 5 of Exhibit___(COSRD-3) provides the Direct Labor O&M expense. In total, for Direct Labor O&M expense, $8,238,396 was classified as Demand, $28,671,724 was classified as Customer, $544,561 was classified as Commodity, and $5,338,801 was classified as Revenue. Exhibit___(COSRD-3), Schedule 1, Pages 6 through 8, provides the direct O&M expense.

In accordance with page 24 of the Commission's August 25, 2004 Order in Case 00-M-0504, Uncollectible Accounts expense (Detail Account 904) has been classified to Revenues. In the same Order, at page 20, customer care (which is represented by portions of customer accounts expense included in Detail Accounts 903 and 901) pertaining to commodity should also be allocated based on Revenues.

Administrative and General Expenses are allocated on Pages 7 and 8 of Exhibit___(COSRD-3), Schedule 1, using a separate study (explained later in this testimony) which was provided in the Workpapers accompanying this panel testimony. The classifications used are provided in Column S of Exhibit___(COSRD-3).

Schedule 2 of Exhibit___(COSRD-3) is the Classification Allocation Factor Report and summarizes the factors used for Total Company (Page 1), the Supply Function (Page 2), the Storage Function (Page 3), the Transmission Function (Page 4), the Distribution Function (Page 5), the Billing and Payment Function (Page 6), the Competitive

1 Energy Services Function (Page 7), and the Clearing
2 Accounts Function (Page 8). Total Company is a
3 summation of the seven individual functions. As
4 noted above, special studies will be explained
5 below.

6 **Cost of Service - Service Class Allocation**

7 Q. Please explain Exhibit___(COSRD-2), Schedule 5.
8 A. Exhibit___(COSRD-2), Schedule 5, provides the
9 Allocation Factors by cost line used to allocate the
10 costs into service classes. The Total Company is a
11 summation of the individual seven Functions and all
12 seven Functions were classified with the same
13 Allocation Factors. The individual Service Class
14 Allocation Factor Reports by Function are included
15 in the Workpapers accompanying this panel testimony.
16 Q. Please describe Exhibit___(COSRD-2), Schedules 1
17 through 4.
18 A. Exhibit___(COSRD-2), Schedule 1 is the Total Company
19 Bundled Service, by service class, for current
20 rates. Distribution's Total Company Bundled Service
21 is the summation of: (1) the Total Company Delivery
22 Service (Exhibit___(COSRD-2), Schedule 2), (2) the

1 Total Company Natural Gas Supply Service
2 (Exhibit___(COSRD-2), Schedule 3),and (3) the Total
3 Company Billing and Payment Service
4 (Exhibit___(COSRD-2), Schedule 4). The individual
5 Functions by Service Class were allocated to the
6 Delivery, Natural Gas Supply, and Billing and
7 Payment Service by the matrix noted above. The
8 Total Company Delivery Service is a summation of the
9 Delivery Service for the individual seven Functions.
10 The Total Company Natural Gas Supply Service is a
11 summation of the Natural Gas Supply Service for the
12 individual seven Functions. Finally, the Total
13 Company Billing and Payment Service is a summation
14 of the Billing and Payment Service for the
15 individual seven Functions.
16 Q. Please describe Exhibit___(COSRD-1), Schedules 1
17 through 4.
18 A. Exhibit___(COSRD-1) was prepared using the same
19 format described above for Exhibit___(COSRD-2),
20 Schedules 1 through 4, with the only exception being
21 that Exhibit___(COSRD-1) is at proposed rates, where
22 Exhibit___(COSRD-2) is at current rates. The

classifications and allocations to service classes have remained the same. As can be seen from the summary page for Total Company Bundled Service, the proposed rates generate a projected rate of return ("ROR") of 7.81% for Total Company.

Cost of Service - Special Allocation Studies

Q. Please elaborate on the three types of studies that were performed; one to determine which Function the costs belong to, a second to determine the Classification of Distribution Mains, and a third to determine the service class allocation.

A. As directed in Case 00-M-0504, additional non-traditional cost of service allocation studies are necessary to determine which costs belonged to which Function. For example, costs embedded in Detail Account 903 (Customer Records and Collections) reflect services defined by Case 00-M-0504 (such as the Billing and Payment Function, the Distribution Function, and the Supply Function). Traditionally, these costs would not have been separately identified, but to comply with the requirements from Case 00-M-0504, Function studies associated with

general plant (and associated reserve and depreciation expense), labor, consumer services (Detail Account 903), and Administrative and General (Control Accounts 401900 and 402900) were completed.

Cost of Service - Function Studies

Q. Please describe the General Plant Allocation.

A. General Plant traditionally has been allocated on a Production Plant + Transmission Plant + Distribution Plant basis, because theoretically General Plant supports the other plant functions. A copy of the General Plant Allocation is provided in the Workpapers accompanying this panel testimony.

Q. Please describe the Structures Allocation.

A. The Company owns facilities supporting employees who put pipe in the ground, employees who answer customer inquiries, and employees who provide administrative functions. The costs associated with this are contained within Structures and Improvements (Plant Account 390). After determining the costs associated with each location, the costs associated solely with the operations of the Company and administrative functions were assigned to the

1 Distribution Function. Costs that were associated
2 solely with the customer inquiry portion of the
3 Company were assigned to the Clearing Account
4 Function. Costs that were shared between operations
5 and customer inquiry were split 50/50 between the
6 Distribution Function and Clearing Account Function.
7 Q. Please explain the All Labor Allocation.
8 A. Company labor direct charged to O&M and the Company
9 clearing accounts has been functionalized according
10 to work performed within the Company. For example,
11 the Telecommunication Clearing (Clearing Account
12 184400) was assigned to the Distribution Function.
13 Detail Accounts 901 (Customer Accounts Supervision)
14 and 903 (Customer Accounts Records and Collections
15 Expenses) were assigned to the Distribution, Billing
16 and Payment, and Supply Functions based on the
17 Consumer Service Allocation. It should be noted
18 that the Consumer Service allocation was prepared in
19 a manner consistent with the Recommended Decision in
20 Case 07-G-0141, at page 81 (allocating customer
21 records and collection costs based on revenues).
22 Labor in Control Accounts 401900

(Administrative and General - Operation) and 402900 (Administrative and General - Maintenance) was assigned based on the Administrative and General ("A&G") study for Detail Account 920000 (Administrative and General Salaries). This study determined that 7.50% was assigned to the Supply Function, 1.92% was assigned to the Transmission Function, 88.48% was assigned to the Distribution Function, 1.39% was assigned to the Billing and Payment Function, and 0.70% was assigned to the Clearing Account Function (with the last 0.01% representing rounding across the various Functions).

Q. Please explain the A&G Allocation.

A. A&G Expenses (Control Accounts 401900 and 402900) were assigned to Corporate Management ("CM"), Consumer Services ("CS"), or Operations, Engineering and Mechanical ("OEM") based on departments. CM was further divided into O&M and non-O&M based on the O&M percentage. Detail Account 928 (Regulatory Commission Expenses) was directly assigned to the Distribution Function based on the March 24, 2003 Recommended Decision in Case 00-M-0504, at page 46.

The remainder of CM O&M was functionalized based on non-A&G labor and non-A&G O&M expenses. CM non-O&M and OEM were functionalized based on Production, Transmission, and Distribution gross plant. CS was functionalized 100% to the Clearing Account.

Cost of Service - Distribution Mains Classification Study

Q. Please describe the Mains Study as provided in the Mains Customer/Demand Workpaper.

A. The first step in determining the allocation of Distribution Mains (Plant Account 376) is the split between Customer and Demand. The Company performed a regression analysis, which determined that 58.56% was customer related and 41.44% was demand related. The regression analysis produced the zero intercept point, based on the relationship between the radius of the pipe size squared and the average cost per foot. Specifically, the cost per foot for a theoretical zero inch radius main was calculated to be $8.273172, and then this cost was multiplied by the total footage of 50,379,672, in order to determine the customer component of mains. This resulted in $416,799,688.91, which is 58.56% of the

1 total cost of $711,725,996.67.

2 **Cost of Service - Service Class Allocation Studies**

3 Q. After costs were classified, how was the proper
4 allocation to the service classes determined?

5 A. The operational characteristics of each account were
6 reviewed to determine the appropriate allocation
7 methodology. For a number of these accounts,
8 special allocation studies were performed. These
9 accounts were Mains (Plant Account 376), Services
10 (Plant Account 380), Meter and Regulator ("M&R")
11 Stations (Plant Account 378), Meters (Plant Account
12 381), Cogeneration Facilities, Uncollectibles
13 Expense (Detail Account 904), Customer Service
14 Expense (Control Account 401800), and Sales
15 Promotion Programs (Control Account 401850).

16 Q. Please describe the Cogeneration study.

17 A. Mains (Plant Account 376) associated with current
18 cogeneration accounts represented $1,300,116.57 of
19 original costs, based on the Company's asset
20 management system records. The depreciation expense
21 was calculated to be $51,484.56 and the accumulated
22 reserve for depreciation was calculated to be

($1,009,171.86).

Q. Please describe the remaining mains (Plant Account 376) study.

A. After the mains demand and customer split was determined (described above), Plant Account 376 was further analyzed for service class allocations into: (1) mains associated with cogeneration, (2) mains greater than or equal to four inch diameter pipe, which were assigned to service classes based on Factor #56 "Peak Day without Cogen," and (3) mains below four inch diameter pipe, which were assigned to service classes based on Factor #78 "Peak Day Remaining Mains."

Q. How were the demand mains greater than or equal to 4" diameter determined in the Mains 4" Allocation Workpaper?

A. The Company summarized footage and costs for Distribution mains, by size, using information from the Company's asset management system. Distribution mains greater than or equal to 4" account for 19,956,952 feet of the total footage, or 49.02%. These mains were then assigned to the service

classes based on Factor #56 "Peak Day without Cogen." The remaining mains were assigned to service classes based on Factor #78 "Peak Day Remaining Mains."

Q. Why do the non-cogeneration mains need to be allocated differently by size?

A. The larger sized distribution mains provide feeder service to smaller customers as well as direct service to larger customers, thereby offering service to all customers. Allocation Factor #56 "Peak Day without Cogen" uses peak day requirements for all service classes, except cogeneration, to allocate larger mains. Smaller-sized mains cannot provide direct service to larger customers, and larger customers do not use smaller mains as feeder systems, therefore these mains are more appropriately allocated to the smaller customers only.

Q. Please describe the Services Allocation.

A. Total costs by size for Plant Account 380 were derived using the Company's asset management system. Total costs were allocated to the appropriate

service classes using information (number of services, by size and service class) from the Company's service line system.

Q. Please describe the Meters Allocation.

A. The company owns meters in order to provide service to customers. Using information available from Company systems, the number of meters by service class was determined. Meter costs were summarized by meter size, using Plant Account 381 from the asset management system. These costs were allocated to the appropriate service class using the number of owned meters by service class. Similarly, the number of Pressure Compensated meters by service class was obtained from Company records and the average costs by meter type were applied to determine the pressure compensated meter investment by service class.

Q. Please explain the Industrial M&R study.

A. The asset management system was queried to determine M&R station costs (Plant Account 385) by location. The locations were then assigned to service classes based upon current customer service class data. For

1 M&R station locations that could not be directly
2 assigned to a service class, an allocation to all
3 classes (except cogeneration and residential
4 service) was completed.
5 Q. Please explain the Uncollectibles Allocation.
6 A. An analysis of write offs, for the twelve months
7 ended December 31, 2015, was performed to determine
8 the appropriate percentage by service class. The
9 Natural Gas Supply Service uncollectible factors
10 were based on SC 1 and SC 3 customer
11 classifications. The Delivery Service and Billing
12 and Payment Service uncollectible factors were based
13 on all customer classifications.
14 Q. Please describe the Customer Service Allocation.
15 A. Control Account 401800 provides customer-oriented
16 services, either with labor dollars or with other
17 O&M expenses. Management from the Company areas
18 responsible for these expenditures assigned costs to
19 service classes that benefit from these services.
20 Q. Please describe the Sales Promotion Allocation.
21 A. Similar to the Customer Service Allocation, Sales
22 Promotion activities (Control Account 401850) were

allocated to the customer classes benefitting from these services.

Q. Have the results of these studies been included in this rate proceeding?

A. Yes. The study results are included in the Workpapers accompanying this panel testimony. It should also be noted that a summary exhibit of studies is included above in this panel testimony.

Marginal Transmission and Distribution Cost

Q. Please describe Exhibit___(COSRD-4), Schedule 1.

A. Exhibit___(COSRD-4), Schedule 1, provides the non-gas transmission and distribution marginal cost study.

Q. What is the definition of transmission and distribution marginal non-gas cost?

A. Marginal non-gas cost is the cost of transmitting and distributing an additional unit of gas. Marginal transmission and distribution costs are the costs associated with additions and modifications to the transmission and distribution system infrastructure that result from increased throughput due to increased sales. This is the cost from the

city gate to the customer, but does not include costs for any equipment inside the customer's premises. The transmission and distribution marginal cost would apply to increased throughput due to new attachments, as well as additional load from existing customers due to an expansion of gas use by existing customers.

Q. Please describe the calculation for the marginal transmission and distribution cost in Exhibit___(COSRD-4), Schedule 1.

A. Exhibit___(COSRD-4), Schedule 1, is a standard analysis for calculating the unit rate per Mcf for gas transmission and distribution marginal cost. This is a traditional approach where there are increases in system throughput along with associated transmission and distribution plant additions. The five year forecast period from October 2016 to September 2021 is being used as a basis for the calculation. The Rate Year (12 months ending March 31, 2018) would be included in this five year forecast period.

Line 1 is the average annual investment in

capital for the transmission and distribution system for the five year period, fiscal 2017 through fiscal 2021, including services, mains and measuring stations. Such capital costs were extracted from the Company's five year Capital Expenditure Program. The average capital investment was annualized by applying a carrying charge of 14.10%, plus an additional 2.70% in annual O&M, to line 1. The total annualized cost on line 5 was then divided by the projected increase in incremental annual throughput (which was developed using information from Exhibit___(VFP-1), Schedule 1), in order to calculate the average marginal transmission and distribution unit rate per Mcf.

Q. What is the conclusion from the transmission and distribution marginal cost study, using the standard method?

A. The standard method produced a unit rate of $166.67 per Mcf, which is not a reasonable result by an order of magnitude. The standard method effectively assumes that all additions to plant result from incremental volumetric demands on the system. This

is an unreasonable assumption considering that the majority of investment in facilities for the Company is associated with replacing existing facilities to meet existing demand. As an alternative to this analysis, the Company has provided an additional study.

Q. Please explain how the marginal cost of plant required to serve customers was determined in this alternative study.

A. As explained previously, utilizing typical marginal cost calculations produces unreasonable results. Therefore, a different approach is necessary in order to estimate the marginal investment cost of serving a customer.

This different approach involved analyzing a sample of specific large system replacement jobs performed by the Company from January 2015 to December 2015. Larger system replacement jobs are useful to analyze because specific mainline replacement costs for a known quantity of customers can be readily identified. The cost estimates resulting from these large system replacement jobs

tend to be conservative, since these projects allow for a more efficient utilization of equipment and crews due to project economies of scale. Also, the Company has, for the most part, already acquired right-of-ways for these projects.

Q. Please describe Exhibit___(COSRD-4), Schedule 2, Pages 1 and 2.

A. Exhibit___(COSRD-4), Schedule 2, Page 2 is a calculation for gas transmission and distribution marginal cost based upon the ten largest projects from January 2015 to December 2015 in the Company's New York system. In the calculation, two jobs had no services or customers associated with the project, so only eight of the ten jobs were used. The total cost, which includes the main installation, main removal, and service costs, was $2,863,057 (line 4). This amount divided by the amount of customers associated with these eight projects results in a cost per customer of $3,619.54, as shown on line 6. The total number of customers on our system is 515,148. The total marginal cost applied to all customers is

$1,864,598,792 ($3,619.54 x 515,148), as shown on line 8.

The total marginal cost of $1,864,598,792 was carried forward to Exhibit___(COSRD-4), Schedule 2, Page 1, which was prepared using the same format as Exhibit___(COSRD-4), Schedule 1. After applying the carrying charge of 14.10% and the O&M percentage of 2.70%, the total annual cost is $313,252,597, as shown on line 5. Dividing line 5 by 102,040,018 Mcf of throughput yields a marginal cost rate of $3.0699 per Mcf. For comparison purposes, the Company has included the Marginal Cost analysis from Case 07-G-0141, to show the variance in the studies based on the data used in the calculation ($3.0699 per Mcf in the current rate filing compares to $5.6093 per Mcf from Case 07-G-0141). Even though the results vary from case to case, Distribution views this calculation as a more reasonable approach for this study, with results being more applicable for conditions in the Company's service territory.

Q. What study is being used for marginal customer costs?

A. For the purposes of this filing, the Company is using the embedded customer cost as a surrogate for marginal customer costs, as shown in Exhibit___(COSRD-1), Schedule 5.

Proposed Rate Design and Associated Tariff Changes

Q. Please provide a general description of Distribution's tariff service rates.

A. Distribution provides services to end use customers and to energy service companies ("ESCO" or "ESCOs").

Services provided to end use customers fall into two broad categories: (1) delivery services and (2) gas supply services. These two broad categories of services are billed to customers through the unbundled charges reflected in Distribution's tariff.

Services to ESCOs include a number of support services that provide ESCOs with access to end use customers on Distribution's system. These services include balancing, billing and a variety of administrative services. These services accommodate the reliable delivery of ESCO supplies to Distribution's system, which in turn are ultimately

1 delivered to end use customers.
2 Q. Is Distribution proposing a new tariff?
3 A. Yes. The new tariff is described in greater detail
4 in the testimony of the Tariff Reorganization Panel.
5 However, for the purpose of this testimony,
6 references to existing service classification
7 numbers will be utilized herein. The testimony of
8 the Tariff Reorganization Panel will provide a
9 translation of existing service classifications to
10 proposed service classifications for reference
11 purposes. Their testimony will also describe in
12 detail the Company's initiative to modernize and
13 update its tariff, which if approved, would become
14 tariff volume number 9.
15 Q. Please provide a general description of the customer
16 rate classifications in the Company's tariff.
17 A. The Company provides unbundled services to the
18 following categories of customers: (1) residential,
19 (2) small, non-residential, (3) large, non-
20 residential, (4) end use based rate classifications,
21 and (5) ESCO and transportation customer services.
22 Exhibit___(COSRD-5) provides a summary of the

1 Company's current tariff service classifications
2 within these five broad categories.
3 Q. What guidelines or criteria should be considered in
4 the design of gas utility rates?
5 A. The design of gas utility rates must, of course, be
6 just and reasonable and avoid undue discrimination.
7 Where rates need to be adjusted toward the
8 achievement of proper cost recovery, customer impact
9 considerations should be factored into the rate
10 design process.
11 Market conditions within the utility service
12 territory, related to the competitive environment
13 faced by the Company's customers, should also be
14 reviewed. Other factors that should be considered
15 in designing rates include: (1) pipeline bypass
16 competition from unregulated suppliers of natural
17 gas, (2) the prices of such alternative pipeline
18 bypass sources of gas relative to Distribution's
19 current and proposed rates, (3) the number of price
20 sensitive customers, and (4) the potential for load
21 loss due to customers switching to other suppliers
22 of natural gas. The loss of customers and gas

volumes in the short-term (e.g., customers switching to alternative fuels, customers switching to alternative suppliers, or other market-based factors such as the migration of production to more competitive regions) can affect a gas utility's ability to recover fully its fixed costs and can reduce a gas utility's chances of earning the allowed rate of return, as determined by a state regulatory body. In the long-term, this can result in increased rates for other customers.

Further, rates should provide financial and earnings stability to Distribution. Toward this goal, generally it is not a sound ratemaking practice to provide for recovery of a substantial portion of fixed costs, such as customer-related and demand-related facility costs that bear no relationship to customer gas consumption patterns, in the rate block portion of the rate schedule. The recovery of fixed costs through commodity rates detracts from earnings stability because the revenues generated from customers' volumetric use of gas can be affected by an overall decline in usage

per account (and thus subject to recovery from sales volumes and revenues that have been declining over the long run). However, with the currently effective revenue decoupling mechanism ("RDM"), this risk, absent the complete loss of the customer, is largely mitigated. The recovery of fixed costs through commodity rates can also be unfair to large heating customers. These customers could be burdened with providing revenue recovery of costs incurred in order to provide service to small volume customers, such as seasonal or recreational residences. The fixed costs of providing delivery services to any individual customer are significant. If the majority of fixed costs are recovered through volumetric rates, then the lower volume customers of any rate class will tend to be subsidized by the higher volume customers in the rate class. This is a particular concern for low income payment troubled customers residing in poor housing stock where their usage significantly exceeds the average customer's usage.

Q. How can cost of service study results provide

1 guidelines for rate design?
2 A. Results of a class allocated cost of service study
3 provide cost guidelines that are useful in
4 evaluating class revenue levels and rate structures.
5 With regard to rate class revenue levels, the rate
6 of return results indicate where certain rate
7 classes are being charged rates that recover more or
8 less than their indicated cost of service. Using
9 the cost study, rate class revenue levels can be
10 brought closer in line with the indicated costs of
11 service. This results in the movement of rate class
12 rates of return toward the system average rate of
13 return, as well as rates that are more in line with
14 the cost of providing service. With respect to the
15 cost justification of rates within each rate class,
16 the classified costs (as allocated to each class of
17 service in the cost study), provide cost information
18 that can be of assistance in determining the need
19 for changes in the relative levels of demand,
20 customer and commodity rate block charges.
21 Q. How are guidelines or criteria, such as the ones
22 just mentioned, generally incorporated into the rate

1 design process?
2 A. The rate design process, which includes both the
3 appointment of revenues to be recovered among
4 customer classes and the determination of rate
5 structures within customer classes, consists of
6 finding a reasonable balance between the various
7 criteria or guidelines that relate to the design of
8 utility rates. Economic, regulatory, historical and
9 social factors all enter into the process.
10 Exhibit___(COSRD-6) further clarifies this by
11 providing criteria of a sound rate structure, which
12 are comprised of revenue-related, cost-related and
13 practical-related attributes to consider as part of
14 the rate design process.
15 In summary, both quantitative and qualitative
16 information are evaluated before reaching a final
17 rate design determination. Of necessity then, the
18 rate design process has to be, in part, influenced
19 by judgmental evaluations.
20 Q. What changes are being proposed to the Company's
21 tariff service rates?
22 A. Generally, the Company is proposing changes to rates

that include changes to delivery charges and changes to the services provided to ESCOs.

Q. Is Distribution proposing changes to the base cost of gas Reserve Capacity Rate in this proceeding?

A. No. The Company is, however, proposing an adjustment to the reserve capacity cost rate calculation based on an analysis that is provided in Exhibit___(COSRD-7). This proposed adjustment would be effectuated in Distribution's monthly Reserve Capacity Cost Adjustment Statement. The basis for the change to capacity included in this monthly statement is described further in the testimony of the Gas Supply Administration Panel and in Exhibit___(GSA-5).

Q. How were the final proposed rates calculated?

A. The final proposed rates were calculated using the methodology that is presented in Exhibit___(COSRD-8). The rate design process, which ultimately derived the final proposed rates, proceeded along the nine steps summarized in this exhibit.

Q. Please describe the first step of the rate design

1 process.
2 A. The first step documented in Exhibit___(COSRD-8)
3 allocates the revenue requirement increase to the
4 service classifications based on each service
5 classification's proportion of non-gas cost revenue.
6 Q. Please describe the second step of the rate design
7 process.
8 A. The second step documented in Exhibit___(COSRD-8)
9 reflects the impact on Company revenue from
10 resetting the revenue decoupling mechanism target,
11 the symmetrical sharing target, and the merchant
12 function charge reconciliation target. Resetting
13 these tracking mechanisms results in a $3,999,352
14 decrease, a $2,200,303 decrease, and a $2,345,031
15 increase, respectively, to the proposed overall
16 revenue recovered in base rates.
17 Q. Please describe the third step of the rate design
18 process.
19 A. The third step documented in Exhibit___(COSRD-8)
20 considers the impact of proposed enhancements to the
21 Company's low income program, which is described in
22 greater detail in the Customer Service Panel

1 testimony. The proposed enhancements result in a
2 $4,694,114 increase to proposed rates.
3 Q. Please describe the fourth step of the rate design
4 process.
5 A. The fourth step documented in Exhibit___(COSRD-8)
6 accounts for proposed changes to the Company's
7 billing charge. Distribution is proposing to reduce
8 the billing charge by 3 cents for all customer
9 classes. This results in an increase to the
10 proposed overall revenue recovered through other
11 base rates, with a $177,876 impact on proposed
12 rates.
13 The billing charge to be included in the
14 minimum charges for all customers that the Company
15 renders a bill to is proposed to decrease by $0.03
16 per bill, from the current rate of $1.07 per bill to
17 $1.04 per bill.
18 Lines (1) through (9) of Exhibit___(COSRD-9)
19 provide a calculation of the unbundled billing
20 charge. The basis for the calculation of the
21 billing charge is the unbundled cost of service
22 study results for billing services. The unbundled

1 billing charge is designed to provide the system
2 average 7.81% rate of return on the rate base
3 determined to support the billing service function.
4 The unbundled billing charge was determined by
5 dividing the total unbundled billing costs by the
6 total amount of customer bills projected to be
7 rendered by the Company for the 12 months ended
8 March 2018. As shown on line (9) of
9 Exhibit___(COSRD-9), the decrease to the billing
10 charge is $0.03 per bill.
11 Q. Please describe the fifth step of the rate design
12 process.
13 A. The fifth step documented in Exhibit___(COSRD-8)
14 makes modifications to the Supply Charge and Records
15 and Collection Charge from Distribution's Merchant
16 Function Charge Statement. These modifications
17 result in a proposed decrease of $3,259,972, to be
18 recovered through other base rate charges.
19 Exhibit___(COSRD-10) provides the calculation
20 of the unbundled merchant function charge for the
21 Supply and Records and Collection components. The
22 basis for the calculation is the unbundled cost of

1 service study results for natural gas supply.
2 Distribution is proposing to combine the Supply and
3 Records and Collection components into one rate,
4 which would be applied to all residential and small
5 non-residential service classification sales
6 volumes. Based on the calculation provided in
7 Exhibit___(COSRD-10), the rate would be $0.31777 per
8 Mcf.
9 Exhibit___(COSRD-15) summarizes the current and
10 proposed supply and records and collection cost
11 charges. As mentioned previously, present rates
12 break out supply procurement and records and
13 collection charges separately, by cost component and
14 by residential and non-residential customer classes.
15 The costs allocated to these classes are reconciled
16 separately by class.
17 Due to a greater proportion of non-residential
18 customers migrating to transportation service, when
19 compared to residential customers, the non-
20 residential reconciliation rates nearly equal the
21 base rates for this class of customers. This method
22 of reconciliation has the potential to lead to

absurd results. For example, should more and more non-residential customers migrate from sales service, the reconciliation rate would grow higher and higher, with the last remaining non-residential customer on sales service facing a $2,110,725 reconciliation rate cost. The cost of service study already is signaling an unusually high rate of return for non-residential gas supply service of 176.24% at current rates.

Under the Company's proposal to roll all supply procurement and records and collection costs into a single rate, the potential "death spiral" reconciliation rate (described above) is avoided. In addition, the rate of return for non-residential gas supply service would drop from 176.24% at current rates, to 43.56% at proposed rates.

Q. Please describe the sixth step of the rate design process.

A. The sixth step documented in Exhibit___(COSRD-8) accounts for a change in the Uncollectible Charge from Distribution's Merchant Function Charge Statement. Specifically, the residential and non-

1 residential uncollectible percentages were updated
2 by dividing the supply portion of uncollectibles
3 into the supply portion of total operating revenues.
4 Updating the Uncollectible Charge increases rates to
5 be recovered through other base rate charges by
6 $1,848,160.
7 The uncollectible percentages are provided in
8 Exhibit___(COSRD-16). For residential service, the
9 uncollectible percentage in the merchant function
10 charge will change from 2.83185% to 1.83690%. For
11 non-residential service, the uncollectible
12 percentage in the merchant function charge will
13 change from 0.40231% to 0.44130%.
14 Q. Does Exhibit___(COSRD-16) also provide the Company's
15 proposed purchase of receivable ("POR") discount
16 rate?
17 A. Yes. The Company is proposing to maintain the
18 current POR rates for residential and non-
19 residential service. Based on line 7 of
20 Exhibit___(COSRD-16), the cost of service study
21 results would indicate that a much higher POR
22 discount rate would be justified. However, such a

1 dramatic increase in POR discount rates would not be
2 consistent with the gradualism concept of rate
3 design. Therefore, the Company is proposing to hold
4 the POR discount rate at current levels and
5 gradually move the implied records and collection
6 contribution towards a more cost-based result.
7 Q. Are you proposing any changes to the storage
8 inventory carrying charges included in the merchant
9 function charge?
10 A. No. The storage inventory carrying charges are
11 excluded from the determination of revenue
12 requirement and are effectively tracked separately.
13 The Company proposes to continue to reconcile any
14 differences in the actual storage inventory carrying
15 charges, with those included in base rates, on an
16 annual basis.
17 Q. Please describe the seventh step of the rate design
18 process.
19 A. The seventh step documented in Exhibit___(COSRD-8)
20 calculates a sub-total of steps one through six of
21 the rate design process, which are described above.
22 The $39,955,744 shown in Exhibit___(COSRD-8) was

derived as follows: $40,350,189 - $3,999,352 - $2,200,303 + $2,345,031 + $4,694,114 + $177,876 - $3,259,972 + $1,848,160. Creating a sub-total in step 7 will help facilitate step 8 of the rate design process.

Q. Please describe the eighth step of the rate design process.

A. The eighth step documented in Exhibit___(COSRD-8) applies the revenue adjustment factor, to the sub-total that was derived in step 7 of the rate design process, for the residential and small non-residential service classifications. The revenue adjustment factor is explained in the direct testimony of Jeremy R. Barber. For the residential service classifications, a revenue adjustment factor of -0.084962% was applied to the sub-total of $31,664,137, which results in a $26,903 decrease in proposed rates. For the small non-residential service classifications, a revenue adjustment factor of -0.310128% was applied to the sub-total of $4,814,807, which results in a $14,932 decrease in proposed rates. In total, the revenue adjustment

1 factor decreases rates to be recovered through other
2 base rate charges by $41,835.
3 Q. Please describe the ninth step of the rate design
4 process.
5 A. The ninth step documented in Exhibit___(COSRD-8)
6 combines the results of steps 7 and 8, both of which
7 are described above. This step adds the impact of
8 the revenue adjustment factor to the sub-total that
9 was derived earlier in the rate design process. The
10 result of step 9 represents Distribution's final
11 proposed rates, to be recovered through changes in
12 the minimum charges and volumetric delivery rate
13 blocks.
14 Q. Please describe how the minimum charge and
15 volumetric block rates were determined.
16 A. For Residential Service Classification Nos. 1 and 2,
17 Distribution recommends recovering 75% of the
18 proposed increase in revenues through increases to
19 the minimum charge and 25% of the proposed increase
20 in revenues through the volumetric block rates. For
21 Service Classification No. 3, Distribution
22 recommends recovering 50% of the proposed increase

in revenues through increases to the minimum charge and 50% of the proposed increase in revenues through the volumetric block rates. For Service Classification No. 13 (TC-1.0, TC-2.0, TC-3.0, TC-4.0, and TC-4.1), Distribution recommends recovering 100% of the proposed increase in revenues through the volumetric block rates.

A summary of current and proposed rates by service classification, including revenue impacts and unit rates, has been provided in Exhibit___(COSRD-13).

Q. Can you provide a summary of proposed changes by tariff service classification?

A. Yes. The summary provided will group each service classification into the five broad categories of services described above: (1) residential, (2) small, non-residential, (3) large, non-residential, (4) end use based rate classifications, and (5) ESCO and transportation customer services. A summary of current and proposed rates has been provided in Exhibit___(COSRD-13).

Q. Please provide a summary of the residential service

1 classifications.

2 A. The service classifications for residential
3 customers are summarized in Exhibit___(COSRD-5).
4 Service Classification No. 1 is the residential
5 service classification. The charges under Service
6 Classification No. 1 are unbundled into two
7 categories: (1) monthly delivery service rates, and
8 (2) Company-provided monthly gas cost supply rates.
9 All residential customers (with the exception of
10 residential customers receiving service through low
11 income rate schedules) receive delivery service
12 through Service Classification No. 1. Residential
13 customers have the choice of receiving monthly gas
14 supply services from Distribution or a qualified
15 ESCO. If the customer chooses to receive monthly
16 gas supply service from an ESCO, the monthly gas
17 supply charge included in Service Classification No.
18 1 is not billed to the customer. The delivery
19 service rate charges for Service Classification No.
20 1 have been provided in the Workpapers accompanying
21 Exhibit___(COSRD-8).

22 Service Classification No. 2 is the Company's

HEAP Residential Assistance Service ("HRAS"). Customers receiving this residential service have received a payment under the federal Home Energy Assistance Program in the current or immediately prior HEAP Plan Year and do not take service under Service Classification Nos. 2A or 2B, which will be described herein. As described in the Customer Service Panel testimony for this proceeding, the Company is proposing to continue the HRAS service, but extend the monthly discount for an additional three months, from five to eight months. The impact of this proposal has been incorporated into the third step of the rate design process.

Service Classification No. 2A is the Company's Elderly, Blind or Disabled ("EBD") Payment-Troubled Residential Assistance Service ("PTRA"). As described in the Customer Service Panel testimony, the EBD PTRA program is a legacy program with a limited number of program participants and the Company is proposing to eliminate the program. Distribution proposes to transfer these customer accounts to Service Classification No. 2, where they

1 will continue to receive a discount on their gas
2 utility bills. In addition, Distribution is
3 proposing an additional credit for these customers
4 in an effort to facilitate an effective transition
5 to a new rate class for these customers. The impact
6 of this proposal has been incorporated into the
7 third step of the rate design process.
8 Service Classification No. 2B is the Company's
9 Low Income Customer Affordability Assistance Program
10 ("LICAAP"). As described in the Customer Service
11 Panel testimony, Distribution's LICAAP program is a
12 targeted program which provides a higher level of
13 benefit to a subset of low income, payment-troubled
14 customers that have a greater need. It provides an
15 affordable gas utility bill to households, based on
16 household income and the number of residents living
17 in the home. The Company is proposing that LICAAP
18 customers that have completed the necessary
19 arrearage forgiveness eligibility period of the
20 program be moved to the broad-based HRAS discount
21 service described above. This proposal is outlined
22 in greater detail in the Customer Service Panel

1 testimony. The impact of this proposal has been
2 incorporated into the third step of the rate design
3 process.
4 Q. Please describe the Company's low income program
5 reconciliation proposal.
6 A. Distribution is proposing an annual reconciliation
7 mechanism, which is described in greater detail
8 below. The reconciliation period for this mechanism
9 will be the twelve months ended March and the
10 surcharge period will be from July 1 through June
11 30.
12 Q. How is the Company proposing to fund its low income
13 programs?
14 A. The Company has included $10,694,114 in the revenue
15 requirement to fund its proposed low income program.
16 The Company is also proposing an annual
17 reconciliation mechanism to track and refund, or
18 recover actual low income program costs, which
19 differ from the amount imputed in the revenue
20 requirement established in this case. The
21 difference between actual low income spending and
22 the amount imputed in the revenue requirement will

be calculated and recovered/refunded based on an adjustment to the volumetric rate of residential customers.

Q. Please provide a summary of the small non-residential service classifications.

A. Service Classification No. 3 is the general service classification for non-residential customers. Similar to Service Classification No. 1, the charges under Service Classification No. 3 are unbundled into two categories: (1) monthly delivery service rates, and (2) Company-provided monthly gas cost supply rates. The delivery service rate charges for Service Classification No. 3 have been provided in Exhibit___(COSRD-13).

Q. Please describe the large non-residential service classifications.

A. Delivery service to large non-residential customers is currently provided through Service Classification Nos. 13D and 13M. Large non-residential customers have an annual consumption greater than 5,000 Mcf per year. Large non-residential customers are further subdivided into the following categories:

(1) SC 13, TC 1.1 - total annual throughput between 5,000 and 25,000 Mcf per year;

(2) SC 13, TC 2.0 - total annual throughput between 25,000 and 55,000 Mcf per year;

(3) SC 13, TC 3.0 - total annual throughput between 55,000 and 150,000 Mcf per year;

(4) SC 13, TC 4.0 - industrial customers with a total annual throughput greater than 150,000 Mcf per year; and

(5) SC 13, TC 4.1 - non-industrial customers with a total annual throughput greater than 150,000 Mcf per year.

The delivery service rate charges for these service classifications have been provided in Exhibit___(COSRD-13).

Q. Please provide a summary of changes proposed for the end use based service classifications.

A. Exhibit___(COSRD-14), Schedule 1, provides a summary of changes for end use based service classifications. The rates for these service classifications have been modified based on the proposed changes being made to Service

1 Classification Nos. 3 and 13.
2 Q. Has the Company proposed any rate changes for
3 Service Classification No. 4?
4 A. Yes. Service Classification No. 4 rates, which are
5 based on rate components of the Service
6 Classification No. 3 and Service Classification No.
7 13 (TC-1 and TC-2), have been updated to reflect the
8 proposed rate changes in these service
9 classifications. The development of Service
10 Classification No. 4 rates is provided in
11 Exhibit___(COSRD-14), Schedule 2.
12 Q. Has the Company proposed any rate changes for
13 Service Classification No. 5?
14 A. Yes. Service Classification No. 5 rates, which are
15 based on rate components of Service Classification
16 No. 13 (TC-3, TC-4 and TC-4.1), have been updated to
17 reflect the proposed rate changes in these service
18 classifications. The development of Service
19 Classification No. 5 rates is provided in
20 Exhibit___(COSRD-14), Schedule 3.
21 Q. Please describe the proposed rate changes for
22 Service Classification No. 7.

A. Exhibit___(COSRD-14), Schedule 4 depicts the methodology utilized to develop the floor and ceiling natural gas vehicle rates ("NGV") for Service Classification No. 7.

Q. Please describe Service Classification No. 8.

A. Service Classification No. 8 was approved by the Commission in Case 90-G-0734. Service Classification No. 8 is applicable to non-residential customers that use gas directly for natural gas-fueled air conditioning equipment. Service Classification No. 8 is a seasonal rate, with one set of base rates in effect for the summer months (May through September - the months with historically significant cooling degree days), and another set of base rates in effect for the remaining non-summer months of the year. For the summer months, the minimum charge for the first 1,000 cubic feet, or less, is equivalent to the minimum charge for Service Classification No. 3. All consumption over 1,000 cubic feet is equivalent to the base commodity cost of gas plus the commodity margin of the Service Classification No. 5 rate.

1 For the non-summer months, the proposed Service
2 Classification No. 8 rate is equal to the Service
3 Classification No. 3 rate.
4 Q. Please describe the development of the summer month
5 rate for all consumption over 1,000 cubic feet for
6 Service Classification No. 8.
7 A. As outlined in Exhibit___(COSRD-14), Schedule 5, the
8 base commodity cost of gas for Service
9 Classification No. 3 (i.e., $0.18730) is added to
10 the commodity margin for Service Classification No.
11 5 (i.e., $0.14250). The resulting rate that is
12 derived is $0.32980 ($0.18730 + $0.14250).
13 Q. Please describe the development of proposed rates
14 for Service Classification No. 9.
15 A. Service Classification No. 9, the small cogeneration
16 sales service rate, is applicable to customers'
17 consumption of natural gas, when the gas is used
18 directly in natural gas-fueled cogeneration
19 equipment. The rate derivation for this service
20 classification is provided in Exhibit___(COSRD-14),
21 Schedule 6.
22 Q. Has the Company proposed any rate changes for

1 Service Classification Nos. 23 and 24?
2 A. Yes. Service Classification No. 23, which
3 represents the non-residential distributed
4 generation ("DG") service rate, is applicable to a
5 non-residential customers' consumption of natural
6 gas, where the gas is used directly for DG less than
7 50 megawatts. The customer is anticipated to
8 maintain a load factor of 50% or greater for the DG
9 facilities receiving service under this rate.
10 Service Classification No. 24, which represents the
11 residential DG service rate, is applicable to a
12 residential customer's consumption of natural gas,
13 where the gas is used directly for DG applications.
14 The rate derivation for both of these service
15 classifications is provided in Exhibit___(COSRD-14),
16 Schedule 7, and Exhibit___(COSRD-14), Schedule 8,
17 respectively.
18 Q. Please explain how the Company's current business
19 development and economic development zone rates were
20 adjusted to reflect the Company's proposed change in
21 revenues.
22 A. The business development rates and economic

development zone/Excelsior rates, applicable to Service Classification Nos. 3 and 13, were adjusted by applying the same percentage that was used to establish the rate discounts in each service class to the appropriate proposed unit rates (exclusive of the base cost of gas). This methodology was previously approved by the Commission. Exhibit___(COSRD-13) includes a summary of the business development and economic development zone rate discounts for Service Classification Nos. 3 and 13.

Q. Has a comparison been performed which compares the effect of the proposed rates on customer retail and transportation bills?

A. Yes. Exhibit___(COSRD-11) presents a comparison of gas bills at various consumption levels under current and proposed rates for Service Classification Nos. 1, 2, 2A, 2B, 3 and 13, respectively.

Pages 6 through 10 of Exhibit___(COSRD-11) provides the current and proposed rates for TC 1.1, TC 2.0, TC 3.0, TC 4.0 and TC 4.1, respectively.

The proposed rates for the various TC categories include an estimated gas supply rate of $0.462673 per Ccf in the last column in order to make the overall impact analysis similar to that provided for sales customers.

Exhibit___(COSRD-17) contains the impact of proposed gas rates, and summarizes (by service classification) the number of bills, rate year sales volumes, revenues at current rates, and revenues at proposed rates.

Q. Please describe the Company's PSC audit and assessment proposal.

A. Distribution is proposing to implement a mechanism to track the differences between what is imputed in rates for the PSC audits and assessments, and the actual costs incurred, on an annual basis.

As described in greater detail in the direct testimony of Ruth M. Friedrich-Alf, there is an initial PSC assessment in January of each year, a true up in August and a final assessment in October. The base amount included in the rate year for this filing is $2,370,000. Also as described in greater

1 detail in the direct testimonies of Evan M. Crahen
2 and Ruth M. Friedrich-Alf, Section 66(19) of the
3 Public Service Law gives the Commission the
4 authority to conduct comprehensive management
5 audits. The base amount included in the rate year
6 for this filing is $837,979, which was derived from
7 the Company's most recent management audit.
8 Q. How is the Company proposing to reconcile the
9 assessment and audit costs?
10 A. The Company has included $3,208,000 in the revenue
11 requirement for regulatory assessment and audit
12 costs. The difference between the actual spending
13 for regulatory assessments and audit, and the
14 imputed amount in rates of $3,208,000, will be
15 determined for the twelve month period ending March
16 31. This difference will be refunded or surcharged
17 to all non-negotiated customers on a unit rate per
18 Mcf basis (utilizing forecasted volumes).
19 Q. Please describe the Company's system upgrade and
20 modernization proposal.
21 A. Distribution is proposing a system upgrade and
22 modernization tracking mechanism. This mechanism

will allow for the recovery of carrying costs associated with the replacement of Leak Prone Pipe ("LPP") above the targeted amounts planned to be replaced, as reflected in the capital spending budget presented in the direct testimony of Kevin D. House.

Exhibit___(COSRD-12) provides a sample calculation for the LPP itemization, which provides an illustrative example of how the dollar amount for cost recovery would be calculated. Referring to line 6, on page 1 of Exhibit___(COSRD-12), the dollar amount of LPP plant carrying costs that would be authorized for cost recovery is outlined for the twelve months ended March 2018, March 2019 and March 2020, respectively. As more fully demonstrated in Exhibit___(COSRD-12), the sample calculation also includes a 200 basis point repeating, cumulative incentive for the Company to accelerate its LPP replacement initiatives. The authorization of cost recovery for the acceleration of Distribution's LPP Replacement Program is consistent with Commission policy objectives and enunciated goals, as set forth

in Case 15-G-0151.

In addition to LPP replacement, the tracking mechanism would permit the recovery of Commission authorized expenditures designed to meet state energy goals. In the long-term, Distribution envisions that the system upgrade and modernization tracking mechanism could also provide cost recovery for Reforming the Energy Vision ("REV") Proceeding (Case 14-M-0101) policy or business initiatives that are approved by the Commission. While the vast majority of the REV Proceeding is focused on reforming the retail electric industry, Distribution's energy efficiency portfolio and certain non-energy efficiency projects and programs could reasonably be seen as advancing REV Proceeding policy objectives, where it practically makes sense for natural gas customers.

As a natural gas only utility, Distribution would not be serving in the capacity of a distributed service platform provider ("DSPP"), as gas utilities should not be involved in dispatching various distributed energy resource ("DER")

technologies on the electric grid. There are, however, opportunities for natural gas utilities to coordinate on electric or multi-fuel projects (in coordination with businesses, market actors, DER providers, peer utilities, the New York State Energy Research and Development Authority, etc.), develop natural gas solutions in order to facilitate electric peak demand reductions (e.g., microgrids), to serve as a primary fuel for electric generation (e.g., distributed generation and micro-combined heat and power), or to serve as a backstop fuel for renewable technologies that could potentially become intermittent from a reliability perspective (again, e.g., distributed generation and micro-combined heat and power, including community aggregation initiatives), among others. This is described in greater detail in the direct testimony and accompanying exhibits of the Energy Services Panel.

In the long-term, the system upgrade and modernization tracking mechanism could be used to support the expansion of advanced metering capabilities, or technological enhancements to

electronic data interchange ("EDI") or related systems in order to further customer engagement initiatives or ensure for the meaningful provision of data, in a secure manner, to ESCOs or DER providers. It should be stressed that the projects identified in this paragraph are presented solely as illustrative examples of items that could reasonably be included in the system upgrade and modernization tracking mechanism for cost recovery purposes. These illustrative examples do not represent projects underway or solutions Distribution is readily endorsing at this time.

To the extent REV Proceeding system upgrade or modernization initiatives are mandated by the Commission, and those mandated initiatives are applied to the natural gas industry, Distribution shall be permitted to include such mandated initiatives in the tracking mechanism without the need for further Commission approval. The Company would prepare a schedule that identifies specific items (and associated dollar amounts) for cost recovery and inclusion in the tracking mechanism.

This schedule would be filed publically with the Commission. This would help expedite the implementation, and furtherance, of such REV initiatives. However, to the extent Distribution believes other non-mandatory REV Proceeding system upgrade or modernization initiatives would be beneficial to its ratepayers, and Distribution chooses to voluntarily implement such initiatives, Distribution would file a letter requesting that the Commission approve the inclusion of such voluntary REV-related initiatives in the Company's tracking mechanism. Accompanying the letter filing would be a schedule that identifies specific items (and associated dollar amounts) for cost recovery and inclusion in the tracking mechanism.

It should also be noted that Distribution proposes to utilize the tracking mechanism to fully recover costs associated with any state or federally mandated safety requirements. To the extent that mandated, additional safety requirements are newly developed, or it is mandated that existing safety requirements be further modified (by the Commission

or any federal regulatory agency), Distribution shall be permitted to include such mandated initiatives in the tracking mechanism without the need for further Commission approval. The Company would prepare a schedule that identifies specific items (and associated dollar amounts) for cost recovery and inclusion in the tracking mechanism. This schedule would be filed publically with the Commission. This would help expedite the implementation, and furtherance, of such safety initiatives. However, to the extent Distribution believes other non-mandatory safety initiatives would be beneficial to its ratepayers, and Distribution chooses to voluntarily implement such initiatives, Distribution would file a letter requesting that the Commission approve the inclusion of such voluntary safety initiatives in the Company's tracking mechanism. Accompanying the letter filing would be a schedule that identifies specific items (and associated dollar amounts) for cost recovery and inclusion in the tracking mechanism.

Q. Please describe the Company's off-system sales and capacity release proposal.

A. In accordance with the most recent Joint Proposal in Case 13-G-0136, $750,000 of off-system sales and capacity release proceeds fund the Gas Network Enhancement Program (referred to as the Gas Expansion Plan in the Joint Proposal) and $250,000 of off-system sales and capacity release proceeds currently fund the Area Development Program. These programs are described in detail in the testimony and accompanying exhibits of the Energy Services Panel.

As described in the direct testimony of Ruth M. Friedrich-Alf, Distribution has included the $250,000 associated with the Area Development Program in the Company's revenue requirement. As a result, at this time, the Company is proposing to discontinue funding the Area Development Program from off-system sales and capacity release proceeds.

Distribution is proposing to continue funding the Gas Network Enhancement Program at the current level of $750,000 per year, using off-system sales

and capacity release proceeds as the funding source. When remaining off-system sales and capacity release proceeds (i.e., the total proceeds less the $750,000 described above) become available for sharing, Distribution would continue the existing practice of retaining 15% of remaining proceeds for shareholder benefit.

As part of the system upgrade and modernization tracking mechanism described above, Distribution is proposing to defer the dollar amount of LPP plant carrying costs that would be authorized for cost recovery.

The ratepayer share of the off-system sales and capacity release proceeds would first be utilized to eliminate any deferral balances accumulated from the system upgrade and modernization tracking mechanism. Any remaining balance for the ratepayer share of off-system sales and capacity release would be refunded to customers.

Q. Does this conclude your panel testimony?

A. Yes, at this time.

corrections to that testimony?

A. No.

Q. If I were to ask you the same questions today would your answers be the same?

A. Yes.

Q. And you adopt this as your sworn testimony in this proceeding?

A. Yes.

MR. NICKSON: Your Honor, I ask -- I ask that the direct testimony of the cost of service and rate design panel consisting of 79 pages of questions and answers be copied into the record as if given orally today.

A.L.J. LECAKES: Granted. The transcript on the CD provided by the company yesterday,National Fuel Gas Distribution Corporation evidentiary hearing, prefiled testimony public in the folder 428-2016 company direct testimony. The file that should be inserted here is the C.O.S. rate design panel direct testimony.

BY MR. NICKSON: (Cont'g.)

Q. And, panel, do you also have a document in front of you entitled the rebuttal testimony of the cost of service and rate design panel --

A. (Crahen) Yes.

Q. -- consisting of 108 pages of questions and answers?

A. Yes.

Q. And was that document prepared by you or under your supervision?

A. Yes.

Q. Did you have any changes to that document?

A. No.

Q. If I were to ask you the same questions today would your answers be the same?

A. Yes.

Q. And do you adopt this as your sworn testimony in this proceeding?

A. Yes.

MR. NICKSON: Your Honor, I ask that the rebuttal testimony, cost of service and rate design panel be copied into the record as if given orally today.

A.L.J. LECAKES: Granted. And so for

the record purposes the transcript should insert the file C.O.S. Rate Design Panel Rebuttal Testimony on that same disc under the folder 916-2016 Company Rebuttal testimony.

CASE 16-G-0257 REBUTTAL TESTIMONY OF THE COST OF SERVICE AND RATE DESIGN PANEL

Q. Please state the names of the members of the Cost of Service and Rate Design Panel ("Panel").

A. We are Eric H. Meinl and Evan M. Crahen.

Q. Mr. Meinl, have you previously submitted testimony in this rate case proceeding?

A. Yes. I provided direct testimony and exhibits regarding a general overview of the rate filing and National Fuel Gas Distribution Corporation's ("Distribution" or the "Company") service territory, an overview of provisions from the last base rate case which the Company proposed to discontinue when rates become effective in this rate proceeding, and a recommended rate of return on equity ("ROE") utilized by the Company in determining the overall revenue increase proposed in this case. In addition, I provided direct testimony, exhibits and workpapers as part of the Cost of Service and Rate Design Panel, and the Volumetric Forecasting Panel. I also provided supplemental direct testimony and exhibits as part of the 2016 Low Income Order Panel.

Q. Mr. Crahen, have you previously submitted testimony in this rate case proceeding?

A. Yes. I provided direct testimony and exhibits regarding Distribution's involvement in recently completed and on-going New York regulatory audits. In addition, I provided direct testimony, exhibits and workpapers as part of the Cost of Service and Rate Design Panel, the Energy Services Panel, and the Working Performance Metric Panel.

Q. What is the purpose of this panel's testimony?

A. The purpose of this panel's testimony is to provide the Company's rebuttal position on various cost of service study and rate design matters presented in the direct testimony of individual witnesses and/or panels of witnesses, including Department of Public Service Staff ("Staff"), Multiple Intervenors ("MI"), Utility Intervention Unit ("UIU"), Public Utility Law Project of New York, Inc. ("PULP"), and intervenor Mr. Richard Ford.

Overview of Rebuttal Testimony

Q. Please describe the layout of this rebuttal testimony.

A. This rebuttal testimony is organized in the following sections:

- General Service Territory Overview;
- Cost of Service Study;
- Rate Design – Allocation of Revenue Requirement Increase;
- Staff – Merchant Function Charge Adjustment
- Staff – Low Income Program Adjustment
- Rate Design – Rate Structure – Service Classification No. 13 Customers;
- Rate Design – Rate Structure – Residential and General Customers;
- PULP – Low Income Housing Cost Burden;
- Price Signal for Conservation;
- UIU – Seasonal Rate Structure;
- Staff – Leak Prone Pipe Mechanism;
- PULP – Two to Four Family Dwellings;
- Regulatory Audits; and
- Closing

General Service Territory Overview

Q. Do the positions of the intervening parties in this case demonstrate a fundamental understanding of the Company's service territory and the current and

expected market conditions for the supply of natural gas service to customers in the Company's service territory?

A. No. It is clear from the testimony of the intervening parties that they do not fully understand the Company's service territory and the evolution of services provided to customers on the Company's system.

Q. Have intervening parties demonstrated any appreciation for the current market position of natural gas in the Company's service territory?

A. No they have not. Exhibit___(COSRD-18), Schedules 1 through 4, provide a series of responses to data requests asked of the parties to determine whether there is an appreciation of the recent decline in the market price of natural gas currently reflected in the Company's sales rates, as well as the market price of natural gas supplies available for delivery to the Company's system for transportation customers.

Q. Have you prepared a summary of the impact of the natural gas price change for residential customers,

in order to provide a demonstration of how this recent decline affects the dollar amount of natural gas bills?

A. Exhibit___(COSRD-19), Schedule 1 provides a summary of the average fuel oil bill, the average Company residential bill, the average Company bill for Low Income Residential Assistance ("LIRA") and Home Energy Assistance Program ("HEAP") Residential Assistance Service ("HRAS" or "HEAP Residential Assistance") customers, and the average Company bill for Low Income Customer Affordability Assistance Program ("LICAAP") customers. This summary is based on the twelve months ended March 2008 and the twelve months ended March 2016. Exhibit__(COSRD-19), Schedule 1 assumes that all customer classes use exactly the same amount of natural gas as the average residential customer, no more and no less. The natural gas bill amounts shown are based on the Company's delivery and gas supply rates in effect for the twelve months ended March 2008 and the twelve months ended March 2016.

Exhibit___(COSRD-19), Schedule 1 demonstrates

that, without any allowance for intervening inflation, the residential customer's annual bill dramatically decreased from $1,631.39 to $746.55, or (54.2%), from 2008 to 2016, for those customers using the same amount of natural gas as the average residential customer. If the impact of inflation were reflected, the decrease would be even more significant. Exhibit___(COSRD-19), Schedule 1 demonstrates that the LIRA and HRAS customer's annual out-of-pocket cost dramatically decreased from $1,035.39 to $308.05, or (70.2%), from 2008 to 2016, for those customers using the same amount of natural gas as the average residential customer.

Exhibit___(COSRD-19), Schedule 1 demonstrates that the LICAAP customer's annual out-of-pocket cost dramatically decreased from $382.83 to $200.51, or (47.6%), from 2008 to 2016, for those customers using the same amount of natural gas as the average residential customer. Stated otherwise, on a budget billing plan (dividing the annual bill by 12 months), the total monthly bill for these customers in 2016 is $16.71 at current rates.

Exhibit___(COSRD-19), Schedule 3 is the same as Exhibit___(COSRD-19), Schedule 1, except for the fact that Exhibit___(COSRD-19), Schedule 3 assumes that all customer classes use 50% more natural gas than the average residential customer uses. Exhibit___(COSRD-19), Schedule 3 demonstrates that the LIRA and HRAS customer's annual out-of-pocket cost dramatically decreased from $1,733.17 to $527.36, or (69.6%), from 2008 to 2016, for those customers using 50% more natural gas than the average residential customer. It should be noted that "out-of-pocket cost" is defined as how much a customer would actually pay for natural gas, after HEAP grants have been applied to the bill, and after bill discounts from the LIRA, HRAS, or LICAAP programs have been applied to the bill.

Q. What general conclusions can be derived from Exhibit___(COSRD-19)?

A. If the goal is to lower the cost of heating a residence in western New York, the above information conclusively demonstrates that the first objective would be to provide access to low cost natural gas

supplies. Such access requires supporting the investment in pipeline infrastructure to deliver those supplies to the region. Since the source of low cost natural gas supplies is primarily across state boundaries, that requires supporting investments in interstate pipelines, as well as the pipeline infrastructure of the local natural gas distribution utility.

Q. Are there any other general considerations which should be recognized when analyzing the cost of service and rate design positions of the intervening parties?

A. Yes. It is useful to have an overall understanding of the Company's service territory to appreciate how rates on the Company's system have evolved and what past New York State Public Service Commission ("Commission") members understood when approving rates for service on the Company's system. Some of this information was provided in the direct testimony of Mr. Meinl submitted in this case. However, given the initial testimony of many of the intervening parties, it is useful to review the

Company's service territory relative to downstate New York service territories, more thoroughly.

Q. Are utility service territories different, when comparing upstate New York to downstate New York?

A. Yes, across New York State there are wide-ranging difference between service territories and geographical areas (e.g., comparing and contrasting metro-New York City to the rural, widespread regions found in central and western New York). These significant differences between upstate and downstate become readily apparent when comparing and contrasting data from the United States Census Bureau.

Q. Is there a report on record that describes these differences?

A. Yes. As part of Case 07-M-0548, Proceeding on Motion of the Commission Regarding an Energy Efficiency Portfolio Standard ("EEPS"), Staff facilitated a number of Collaborative Working Groups to explore topics of interest, in order to inform the record for New York State energy policy determinations. As part of Phase II of the

Collaborative, Working Group V issued a Final Report on Natural Gas Efficiency Goals. Included in this Report is an analysis of upstate/downstate disparity and the uniqueness of each service territory, using United States Census Bureau information. A copy of the cover page from this report, along with the relevant section of this report including the aforementioned analysis, is provided as Exhibit___(COSRD-20).

Q. What information is contained in the Report on Natural Gas Efficiency Goals?

A. The information contained in the Report on Natural Gas Efficiency Goals is as follows:

- "The percentage of housing units that use natural gas as their primary heating source is much greater upstate as compared to downstate." In Buffalo, 87% of all customers heat with natural gas and 84% of customers with incomes below the poverty level heat with natural gas. This compares with 39% and 30% respectively in New York City.

- "A major distinction between upstate and New York City is that in the City there are more cooking-only customers and more customers are below [the] poverty level." In Buffalo, 5% of all customers are cooking-only and 7% of customers with incomes below the poverty level are cooking-only. This compares with 53% and 67% respectively in New York City.
- "The disparity between owner occupied and renter occupied housing in upstate and downstate metropolitan areas is also significant." In Buffalo, 68% of all customers reside in owner occupied housing units and 31% of customers with incomes below the poverty level reside in owner occupied housing units. This compares with 46% and 16% respectively in New York City.
- "While households below the poverty level have lower owner occupied units across New York State, the proportion of low income owner occupied housing units is twice that in upstate

versus downstate metropolitan areas."

- "The greater abundance of rental units downstate is further demonstrated by the significantly greater population of households that live in multi-family (greater than four unit) buildings in downstate metropolitan areas compared to upstate metropolitan areas." In Buffalo, 92% of all customers reside in one to four unit households and 81% of customers with incomes below the poverty level reside in one to four unit households. This compares with 45% and 68% respectively in New York City.
- "This disparity in types of housing units between upstate and downstate influences the type of heating equipment that is utilized between upstate and downstate. In New York City there is a large percentage of households who heat with steam or hot water in their homes, as opposed to upstate where forced air is dominant." In Buffalo, 73% of all customers heat with forced air furnaces and 66% of

customers with incomes below the poverty level heat with forced air furnaces. This compares with 20% and 15% respectively in New York City.

- In Buffalo, 9% of all customers have piped gas included in their rent and 22% of customers with incomes below the poverty level have piped gas included in their rent. This compares with 40% and 50% respectively in New York City.
- "The age of housing units occupied by customers with income below poverty compared to the average customer can also vary significantly by region." In Buffalo, the median year of housing structure construction for all customers was 1951 and the median year of housing structure construction for customers with incomes below the poverty level was 1934. This compares with medians of 1950 and 1946 respectively in New York City.
- "There are differences in customer mix between upstate and downstate, and even between gas utility service territories. For instance,

there is a higher concentration of C/I [commercial and industrial] customers upstate than downstate, particularly in the manufacturing sector. This sector is confronted with extraordinary economic challenges and [the sector] has been declining in the State."

Q. Why is the Report on Natural Gas Efficiency Goals important?

A. The Report on Natural Gas Efficiency Goals is important because it provides a concise summary demonstrating Distribution's service territory is significantly different than other utility service territories in New York State. It also provides important background information that the intervening parties ignored in developing their recommendations (as will be further discussed later in rebuttal testimony).

Q. Does this complete your overview of the Company's service territory?

A. Yes, with this more thorough background of the Company's service territory, we will now address

specific issues from the cost of service and rate design direct testimony and exhibits of the parties.

Cost of Service Study

Q. Are the intervening parties' cost of service recommendations consistent with the operational and market conditions experienced in the Company's service territory?

A. No. It is clear from the intervening parties' testimony and responses to data request questions from Distribution that they do not appreciate the operational and market conditions of the Company's service territory. For example, UIU at 41, states "the same service may deliver gas to retail stores and offices of widely varying sizes located in the same building. Similarly, the same service may be used by apartments of widely varying sizes, placing different demands on the service." While this may be a significant factor for downstate service territories where, as identified previously, only 45% of households reside in one to four unit buildings, it is much less likely in Buffalo, where 92% of households reside in one to four unit

buildings. UIU's testimony repeatedly cites Commission Orders from other service territories (many of which are from out-of-state Commissions), but provides no evidence that it understands the market conditions in the Company's service territory.

Q. Is it appropriate to apply cost of service policy determinations from other utilities on Distribution?

A. No. Arbitrarily applying cost of service policy determinations on Distribution, without considering the unique circumstances of the Company's service territory and customer base is inappropriate and misleading. An example of this occurs in the UIU's direct testimony (pages 20 and 21). The results of the cases cited by UIU simply over-allocate costs to the large volume customer classes, from the residential and general customer classes.

Q. Is Distribution's service territory different than other utility service territories outside of New York State?

A. Yes, significantly different, as described above in the General Service Territory Overview section of

this rebuttal testimony. In addition, many of the service territory differences were also described in the direct testimony of Mr. Meinl.

Q. Is there another important consideration to recognize about the Company's service territory?

A. Yes. The Company's service territory is among the coldest of major metropolitan areas in the United States.

Q. Please provide a summary of heating degree days, by census region, using United States Energy Information Administration ("EIA") data.

A. A summary of EIA's heating degree day data, depicted graphically, is provided in Exhibit___(COSRD-21), Schedule 1.

Q. What does Exhibit___(COSRD-21), Schedule 1 demonstrate?

A. Exhibit___(COSRD-21), Schedule 1 demonstrates that New York State has significantly different heating degree days when compared to Florida, Illinois, Massachusetts, Michigan, Washington and West Virginia, the exact states cited in UIU's testimony, at pages 22 through 27. As a result, it is not

appropriate to arbitrarily apply cost of service policy determinations on Distribution from any of these states, as each state experiences different weather conditions. Weather conditions are important, since they impact the intended use and engineering design of gas distribution systems. They also provide real world limitations on the amount of conservation efforts that can reasonably be expected from customers, as will be explained later in this Panel's rebuttal testimony.

Q. Does the Panel have any additional heating degree day data?

A. Yes. Exhibit___(COSRD-21), Schedule 2 provides a summary of normal heating degree days, based on comparative climatic data from cities across the United States, from the National Oceanic and Atmospheric Administration ("NOAA"). NOAA is an agency of the United States Department of Commerce.

Q. What does Exhibit___(COSRD-21), Schedule 2 demonstrate?

A. Similar to Exhibit___(COSRD-21), Schedule 1, Exhibit___(COSRD-21), Schedule 2 demonstrates that

states experience different weather conditions compared to each other. Even within states, there are different weather conditions. For example, Buffalo is 39.3% colder than New York City (Central Park weather station) at normal weather.

Q. Please describe the cost of service study summary recommendation from the UIU Rate Panel.

A. UIU rejects the Company's proposed method of allocating the costs of gas distribution mains (Federal Energy Regulatory Commission ("FERC") Account 376) as partially demand-related and partially customer-related. Instead, UIU recommends these costs be allocated based solely upon the demand placed on the distribution system by each customer class. It should be noted that UIU, at page 11, claims that the classification of costs step in performing cost of service studies is "controversial."

Q. Does the Company agree with UIU's cost of service study recommendation?

A. No, the recommendation should be rejected. UIU's assertions are factually incorrect, as described

herein. Number of customers is an important consideration in planning, installing, and renewing distribution mains, especially in the Company's service territory, which is different than the conditions experienced in states outside of New York, and in downstate New York. In fact, UIU at 16, acknowledges "the minimum cost of the distribution system varies as a function of the number miles of streets served by the system while the remaining cost primarily varies with the anticipated peak load that each main is expected to accommodate over its useful life." Therefore, there is no dispute that a cost causal relationship exists between the number of customers served and miles of distribution main.

Q. As respects Distribution and the specific circumstances of the Company's service territory described above, is the cost allocation of gas distribution mains, as partially demand-related and partially customer-related, reasonable?

A. Yes, this allocation methodology is reasonable and should not at all be controversial in this case. In

fact, the cost of service study issues being raised by UIU in this rate proceeding are precisely the same issues that were already resolved by the Commission in a Company rate proceeding roughly twenty years ago. The recommended decision by Administrative Law Judge ("ALJ") Robinson, issued June 15, 1995 ("June 1995 Recommended Decision") in Case 94-G-0885, as well as the Commission's Opinion and Order Determining Revenue Requirement and Rate Design, issued and effective September 15, 1995 ("September 1995 Order"), in Cases 94-G-0885 and 93-G-0756, both confirm this fact.

Q. Please describe the Consumer Protection Board ("CPB") (UIU's predecessor) position, as outlined in the June 1995 Recommended Decision, as it pertains to Distribution's allocation methodology for mains.

A. The June 1995 Recommended Decision, at page 89, describes the CPB took exception with the Company's use of a minimum distribution system concept to assign distribution system costs.

Q. Please describe Staff's reply position, as outlined in the June 1995 Recommended Decision, as it

pertains to Distribution's allocation methodology for mains.

A. Staff argued that one could reasonably question the extent to which current and future distribution plant costs would be demand-related for a utility that is nearly free of distribution capacity restraints [such as Distribution] and has low growth. Staff also argued that a significant percentage of such plant costs would actually be capitalized labor, which would likely vary directly with the geographical scope of distribution plant work, rather than with the capacity of the plant.

Q. Please describe the Company's reply position, as outlined in the June 1995 Recommended Decision, as it pertains to Distribution's allocation methodology for mains.

A. Distribution argued it defies common sense to deny any correlation between miles of main and numbers of customers. While mileage per customer may vary, clearly mains must exist to serve customers.

Q. Please describe the ALJ's position, as outlined in the June 1995 Recommended Decision, as it pertains

to Distribution's allocation methodology for mains.

A. The ALJ concluded that CPB did not make a sufficiently persuasive case for overturning the Company's proposal. In addition, the ALJ recognized that cost of service is not an exact science, and that the results of such studies can only be taken as approximations. The ALJ further concluded that cost of service studies are complex undertakings, which entail much use of judgment in methodological choices, and that one can always take issue with certain aspects of any cost study, changing the results by changing the techniques employed.

Q. Given this position, what was the final decision of the ALJ in the June 1995 Recommended Decision?

A. The ALJ's final decision was that "the concept of a minimum distribution system makes some sense because clearly no customer can be served without one, and furthermore, the Company used a conservative version of this concept, in effect emphasizing the 'minimum'

in the minimum distribution system."[1] Consequently, the ALJ recommended that the Company's approach should be adopted.

Q. Given the ALJ's decision in the June 1995 Recommended Decision, what did the Commission ultimately order in the September 1995 Order?

A. The Commission denied CPB's exceptions, noting the exceptions were fully addressed and properly rejected in the June 1995 Recommended Decision.

Q. Is any additional commentary included in the September 1995 Order?

A. Yes, the September 1995 Order describes Staff's reply position in greater detail. Specifically, the September 1995 Order states "no responsible rate analyst would rely wholly on an embedded cost study to set gas rates; but such a study does provide some guidance about the direction and magnitude of rate changes required to ensure that rates remain competitive."

Q. How does the June 1995 Recommended Decision and the

[1] The same conservative approach was applied in the Company's analysis during this proceeding, as respects comparing the Company's results to a 4 inch main analysis.

September 1995 Order relate to this proceeding?

A. As described above, the cost of service study issues being raised by UIU in this proceeding are the same issues that were already addressed by the Commission in a Company rate proceeding roughly twenty years ago.

Q. Does the Company agree with the June 1995 Recommended Decision and the September 1995 Order?

A. Yes. Distribution agrees with the June 1995 Recommended Decision, as respects the cost of service study determination. The Commission's September 1995 Order, as respects the cost of service study determination, should be reaffirmed in this rate proceeding since it is consistent with the facts, as they apply to Distribution's system today.

Q. Did the Company explain in detail why it proposed to allocate the costs of gas distribution mains as partially demand-related and partially customer-related?

A. Yes, Distribution's minimum distribution system analysis was described in detail in the direct testimony of the Cost of Service and Rate Design

Panel, at pages 29 through 32. UIU's claim to the contrary, at page 14, is unfounded. It should also be noted that UIU, at page 27, conceded that "the minimum system approach is sometimes used by other New York utilities."

Q. Please describe UIU's position pertaining to customers using a product significantly more than other customers using the same product.

A. At page 16, UIU states "customers who value the product most, or purchase the largest quantity, typically pay a larger share of joint costs than customers who buy less, or value the product less."

Q. Will customers that buy more gas on the Company's system be charged more for delivery service than those that use less?

A. Yes, Exhibit___(COSRD-22) confirms this fact. What UIU is actually saying is that customers that use more gas should pay an even greater share of the system's fixed costs than they pay today. Of course, as a customer uses more, their average per unit costs will be less, but this reflects economies of scale and is completely consistent with

competitive markets.

Q. Hypothetically, what would UIU's position mean for low income customers?

A. From a purely hypothetical construct, if this position is taken literally, the result is that low income customers with the highest usage of natural gas should pay more than other residential customers, simply because they use more gas, and in turn, "value" the product more than other residential customers.

The workpapers supporting Exhibit___(JRB-1) include the number of bills issued by service classification, as well as usage for the historic test year. Using these workpapers mathematically, Service Classification No. 1 residential customers used 104.3 Mcf during the historic test year (33,461,896 / (3,849,525 / 12)) = 104.3 (Sheet 1)) and Service Classification No. 2B LICAAP customers used 139.7 Mcf during the historic test year (1,502,439 / (129,082/12)) = 139.7 (Sheet 4)). UIU is essentially recommending that LICAAP customers should pay 33.9% (((139.7 – 104.3) / 104.3) = 33.9%)

more than the average residential customer for delivery service, simply on the basis that these customers use more gas. This completely disregards the fact that the low usage residential customer will have incurred the same amount of fixed costs to be connected to the system as the high usage residential customer. We will explore the consequences of UIU's recommendation, when the Panel addresses the various minimum charge proposals of the parties later in rebuttal testimony.

Q. Does UIU cite the National Association of Regulatory Utility Commissioners ("NARUC") Gas Distribution Rate Design Manual to support its position, as respects allocating the cost of mains solely on the basis of demand?

A. Yes, UIU cites NARUC's Gas Distribution Rate Design Manual, at pages 19 and 20 in their direct testimony.

Q. Does the NARUC Gas Distribution Rate Design Manual also support Distribution's position, as respects the allocation of the cost of mains?

A. Yes. NARUC's Gas Distribution Rate Design Manual,

at page 22, states "a portion of the costs associated with the distribution system may be included as customer costs." The Manual, at page 22, states "one argument for inclusion of distribution related items in the customer cost classification is the 'zero or minimum size main theory.' This theory assumes that there is a zero or minimum size main necessary to connect the customer to the system and thus affords the customer an opportunity to take service if he so desires." Of course, this is the same theory that was approved by the Commission twenty years ago, as it applies to Distribution.

Q. Does the NARUC Gas Distribution Rate Design Manual also recognize a minimum size analysis as a valid allocation methodology?

A. Yes. NARUC's Gas Distribution Rate Design Manual, at page 22, states "under the minimum size main theory, all distribution mains are priced out at the historic unit cost of the smallest main installed in the system, and assigned as customer costs. The remaining book cost of distribution mains is

assigned to demand."

Q. Does the number of customers directly relate to the cost of mains?

A. Yes, despite Mr. Ford's assertion to the contrary, at page 1 of his direct testimony. On a fundamental basis, it is impossible for a utility to serve a customer without a main providing natural gas service to their residence or place of business. There is a fixed cost associated with excavating, constructing and installing mainlines, running services to those mainlines, and ultimately equipping each customer with a regulator and meter set. One of the largest drivers of mainline costs is the number of customers, as the number of customers determines the length of mainline that is needed. UIU's value-based model of utility service development completely ignores the system renewal issue. The Company is currently in the process of replacing its older pipe in well-established residential neighborhoods. The Company does not consider the amount of revenues contributed by any single residential customer in those well-

established neighborhoods, when determining whether to renew the mainline extending to that home or the service line connected to that house. The Company will not abandon a low usage low revenue customer during a system renewal, even if the revenues generated from that account do not recover the incremental cost of renewing the service line and meter set of the customer, nor would the Commission authorize the abandonment of any such low usage low income customer in a well-established neighborhood.

Q. Does UIU describe their understanding of how the Company's service lines are utilized?

A. Yes. UIU, at page 40, states "a single service can be shared by multiple customers of varying sizes. For example, the same service may deliver gas to retail stores and offices of widely varying sizes located in the same building. Similarly, the same service may be used by apartments of widely varying sizes, placing different demands on the service."

Q. Does Distribution agree with UIU's understanding of how the Company's service lines are utilized?

A. No, this assessment is factually incorrect.

Although this description may be accurate in the service territories of downstate utilities, where mixed use customers are "sharing services," it is not the typical case in the Company's service territory. Within Distribution's service territory, service lines are not routinely "shared" between commercial facilities and residential dwellings, as suggested by UIU, since as explained previously, most residential households in the Company's service territory are in one to four unit buildings.

Exhibit___(COSRD-23), Schedules 1 and 2 provide two maps of areas in the Company's service territory, from the Company's Geographic Information System ("GIS"). These maps are from a high income zip code (14051) and a low income zip code (14215) of the Company's service territory. Commercial and industrial customers in the Company's service territory are predominantly located on major thoroughfares and served by distribution mains that feed gas into mains that exclusively serve residential neighborhoods. Mainlines running alongside roads, up and down streets, are largely

intended for residential use, further substantiating the Company's proposal, that the cost of mains is directly driven by the number of customers, as the number of customers determines the length of mainline and number of services that are needed to serve customers, especially in residential areas.

In summary, mixed use facilities that are largely present in metropolitan New York City are largely absent in Distribution's service territory. Consider Manhattan or Brooklyn, where storefronts may be prevalent in the first two stories of a building. Above the first or second story, residential customers generally reside in multi-unit dwellings. This phenomenon is not as prevalent in the Company's service territory, where services to residential buildings are designed to serve residential customers and services to commercial buildings are designed to serve commercial customers.

Q. What zero intercept was calculated in Distribution's minimum size analysis?

A. A zero intercept of $8.27 per foot was calculated in

the Company's minimum size analysis.

Q. Is this zero intercept value reasonable?

A. Yes. Exhibit___(COSRD-24) provides a summary of the Company's zero intercept analysis and compares those results to the minimum system method that is the alternative method for determining the customer costs of mains referenced by the NARUC Gas Distribution Rate Design Manual.

Q. Did Distribution's minimum size analysis exclude certain pipe types?

A. Yes. Exhibit___(COSRD-24) demonstrates that 0.49% of the Company's pipe was excluded from the analysis. This pipe represents non-standard, legacy pipe sizes that are not indicative of pipe sizes typically installed in gas distribution systems. Indeed, over 95% of the 0.49% of excluded pipe was installed in the last century. These anomalous pipe sizes were removed from the analysis since it would be inappropriate to include outlier data in the analysis.

Q. Please summarize UIU's position, as respects the statistical approach employed by Distribution in the

minimum size analysis.

A. UIU recommends a multiple regression be employed instead of a linear regression, for the minimum size analysis.

Q. Did UIU present a multiple regression analysis in this proceeding?

A. No, despite UIU's claims that a multiple regression analysis is "preferred" over a linear regression analysis, a multiple regression analysis was not presented by UIU in this rate proceeding. It should also be noted that UIU provides no numerical or analytic studies to justify or support their position. Instead, UIU simply criticizes the long-recognized methods for estimating the customer portion of distribution mains as identified in the NARUC Gas Distribution Rate Design Manual.

Q. Does UIU make any additional comments pertaining to Distribution's cost of service study?

A. Yes. UIU, at page 32, recommends that a cost of service study classifying distribution mains as 100% demand-related be presented in future rate proceedings.

Q. Does the Company agree with this recommendation?

A. No, as described above, Distribution does not agree with the methodology of classifying distribution mains as 100% demand-related, which, as the Panel noted previously, was rejected by the Commission in the past. Such an approach simply over-allocates costs to the large volume customer classes, from the residential and general customer classes. UIU's testimony, at pages 32 and 33, also conceded that the Company produced a cost of service study analysis in this proceeding, in response to UIU's data request, which classified distribution mains as 100% demand-related. Since the study was prepared by the Company when asked, there is no need to establish an administratively burdensome requirement that impacts future rate proceedings.

Q. Does the Company agree with the result of the cost of service study which classifies distribution mains as 100% demand-related?

A. No. Although the Company ran the cost of service study provided to UIU as a courtesy, Distribution stated clearly that "the Company believes that

running the scenario in the way requested is unwarranted and unsound. Distribution, accordingly, disclaims the mechanical results produced and would dispute any claim that running a scenario in this fashion is appropriate."

Q. Please describe the result of MI's review of Distribution's cost of service study.

A. MI, at page 4, concluded that Distribution's cost of service study comports with accepted industry practices. In addition, MI cites "the study recognizes the different types of costs, as well as the different ways natural gas is delivered to customers. Further, the cost classifications and allocations generally comport with ECOS [embedded cost of service] studies filed by other natural gas utilities, including utilities providing gas/delivery services to retail customers in New York."

Q. Did MI make any cost of service study recommendations?

A. Yes, at page 15, MI recommends that the Commission should order Distribution to conduct a "full"

customer cost of service study in its next rate case. MI claims that Distribution has not quantified cost-based minimum charges.

Q. Does Distribution agree with this recommendation?

A. No, MI's recommendation should be rejected by the Commission. Distribution has presented a "full" customer cost of service study in this proceeding, as evidenced by the Schedules presented in Exhibit___(COSRD-1), Exhibit___(COSRD-2), and Exhibit___(COSRD-3). Specifically, Distribution quantified cost-based minimum charges and presented the results of such quantification in Exhibit___(COSRD-1), Schedule 5. Since Distribution already quantified cost-based minimum charges and presented them in this proceeding, there is no need to establish a requirement for something that has already been completed.

Q. Please describe Staff's testimony, as respects how a cost of service study influences revenue allocation and rate design.

A. Staff's testimony, at page 72, states "the results of the COS [cost of service] study serve as a

guideline [emphasis added] for determining the allocation of revenue increases/decreases between service classifications."

Q. Does Distribution agree with Staff's characterization describing how results of cost of service studies should be used?

A. Yes, a cost of service study serves as a guideline and is one of many attributes to consider as part of the rate design process. This was described in greater detail in the direct testimony of the Cost of Service and Rate Design Panel, at pages 43 through 47. In addition, Exhibit___(COSRD-6) accompanying the Cost of Service and Rate Design Panel's direct testimony, provides criteria of a sound rate structure, which are composed of revenue-related, cost-related and practical-related attributes to consider as part of the rate design process.

The rate design process, which includes both the appointment of revenues to be recovered among customer classes and the determination of rate structures within customer classes, consists of

finding a reasonable balance between the various criteria or guidelines that relate to the design of utility rates. Economic, regulatory, historical and social factors all enter into the process.

Q. Please describe the result of Staff's review of Distribution's cost of service study.

A. Staff, at page 73, stated "generally speaking, we believe the COS [cost of service] study to be reasonable."

Q. Please describe how Staff used the cost of service study in this proceeding.

A. Staff, at page 74, stated "we used the COS [cost of service] study as a tool to aid in the revenue allocation and rate design process. Since there are many assumptions used in the development of a study of this nature, the cost study can be used as a guide for the revenue allocations within the Company's service classifications."

Q. Does the Company agree with Staff's use of the cost of service study?

A. Yes, Staff's use of the study comports with the Company's description of the intended use of a cost

of service study, as described in direct testimony and exhibits of the Cost of Service and Rate Design Panel, at pages 43 through 47.

Q. Did Staff note any areas of disagreement, as respects the cost of service study?

A. Yes. Staff, at page 74, stated the "results of the zero intercept methodology may under-allocate costs to classes that have large demands placed on the system and few customers."

Q. Does Distribution agree with Staff's claim?

A. No, the Commission should reject Staff's claim. Staff did not provide numerical analyses, analytic studies, or exhibits to substantiate their claim.

Rate Design – Allocation of Revenue Requirement Increase

Q. In your direct testimony, the Panel proposed that the revenue requirement increase be allocated to the individual service classifications based on each service classification's proportion of non-gas revenues. Do the intervening parties agree with this proposal?

A. Staff agrees that this proposal is reasonable. MI and UIU provide an alternative cost allocation

recommendation.

Q. Please describe MI's position, as respects the use of a cost of service study for the purpose of rate design.

A. MI, at page 8, advocates that "cost of service should be the primary criteria used to determine class revenue allocation."

Q. Is MI's position consistent with Staff's position in this proceeding?

A. No. As noted above, Staff (at 74) stated, "we used the COS [cost of service] study as a tool to aid in the revenue allocation and rate design process. Since there are many assumptions used in the development of a study of this nature, the cost study can be used as a guide for the revenue allocations within the Company's service classifications."

Q. Did Staff find the Company's methodology for allocating revenues reasonable?

A. Yes. Staff, at page 75, stated "the Company did not propose to shift revenues to correct for return imbalances as shown in the COS [cost of service]

study. We [Staff], therefore, believe the methodology is reasonable."

Q. Please describe UIU's position, as respects the use of a cost of service study for the purpose of rate design.

A. UIU states (at page 12) "an ECOS [embedded cost of service study] is often developed in rate proceedings for potential use in determining how to allocate the revenue requirement across classes (often referred to as 'revenue allocation') and in developing various gas rate design proposals.

Q. Should cost of service studies be the sole criterion relied on for class revenue allocation?

A. No. As described in the direct testimony of the Cost of Service and Rate Design Panel, the rate design process, which includes both the appointment of revenues to be recovered among customer classes and the determination of rate structures within customer classes, consists of finding a reasonable balance between the various criteria or guidelines that relate to the design of utility rates. Economic, regulatory, historical and social factors

all enter into the process. Exhibit___(COSRD-6) further clarifies this by providing criteria of a sound rate structure, which are composed of revenue-related, cost-related and practical-related attributes to consider as part of the rate design process. Both quantitative and qualitative information are evaluated before reaching a final rate design determination.

Q. Please describe MI's awareness of the benefits accruing to Distribution's service territory, from hydraulically fractured gas supplies in Appalachia?

A. During discovery, Distribution identified that MI is not aware of the benefits accruing to Distribution's service territory. As a result, MI has not attempted to quantify such benefits realized by its customers. A copy of MI's data request response, confirming this fact, is provided as Exhibit___(COSRD-18), Schedule 4.

Q. What is MI's proposal, as respects rate design?

A. MI, at page 12, recommends "SC-1 and Cogen [cogeneration] service classes receive a non-gas revenue increase that is at least 1.25 times the

system average increase. The remaining service classes should receive below-average increases to move each [service classification] closer to cost."

Q. Does Distribution agree with MI's "dead band" proposal?

A. No, the Commission should reject MI's "dead band" proposal. The Company is forecasting that it will be providing interruptible service to only one cogeneration customer in this proceeding. That customer is provided delivery service and does not receive monthly commodity service from the Company. The delivery rate for service to that customer was established under contact, and as a result does not change month to month. The revenues generated by that customer are contingent on whether they are dispatched to generate electricity by the New York Independent System Operator ("NYISO"). Those revenues can be highly volatile. This customer class is also subject to the 90/10 revenue sharing arrangement and therefore, if greater revenues are achieved than imputed, 90% will be allocated to the benefit of customers.

Q. Does MI cite other New York State proceedings to support its dead band proposal?

A. Yes, MI makes reference to Cases 08-E-0539 and 08-M-0618 (Con Edison), Case 07-S-1315 (Con Edison), and Cases 00-E-1273 and 00-G-1274 (Central Hudson), to support the dead band proposal.

As described in the Cost of Service section of this panel's rebuttal testimony, arbitrarily applying rate design policy determinations on Distribution, without considering the circumstances of the Company's service territory and customer base is inappropriate. There are wide-ranging differences between service territories and geographical areas in New York (e.g., comparing and contrasting metro-New York City to the rural, widespread regions found in central and western New York).

As respects Cases 08-E-0539 and 08-M-0618, the cases referenced by MI relate to electric industry dead bands, not at all the natural gas industry.

As respects Case 07-S-1315, the case referenced by MI relates to steam industry dead bands, not at all the natural gas industry.

With respect to Cases 00-E-1273 and 00-G-1274, the cases referenced by MI appear to relate to both the natural gas and electric industry. However, Distribution's review of the Commission's Order Establishing Rates, issued and effective October 25, 2001 in Cases 00-E-1273 and 00-G-1274, indicates that the referenced Cases only relate to electric industry dead bands, not at all the natural gas industry.[2]

Staff – Merchant Function Charge Adjustment

Q. Please describe Staff's merchant function charge ("MFC") rate design adjustment.

A. Staff, at page 76, states "the Panel recognizes adjustments made by that Staff Witness Davi to reflect updates to the uncollectible percentage."

Q. Does the Company agree with Staff's uncollectible percentage?

A. No. Because the Company does not agree with Staff's uncollectible percentage for the reasons stated in the testimony of Ms. Frank, the Company does not

[2] Cases 00-E-1273 and 00-G-1274 – Order Establishing Rates, at 6 and page 22 of Attachment B to the Order (Joint Proposal).

agree with Staff's merchant function charge rate design adjustment.

During discovery, Staff responded to a data request from Distribution admitting that their calculation required further refinement. As such, Distribution does not agree with Staff's calculation. A copy of Staff's response, confirming this fact, is provided as Exhibit___(COSRD-25).

Q. Does Staff provide any additional detail?

A. Yes. Staff, at page 76, states "the final MFC rate should ultimately be updated to reflect the Commission approved uncollectible rate."

Q. Does Distribution agree?

A. Yes. The final merchant function rate should ultimately be updated to reflect the Commission approved uncollectible rate.

Staff – Low Income Program Adjustment

Q. Please describe Staff's low income program rate design adjustment.

A. Staff, at pages 75 and 76, recommends that the cost of the low income program be included in Distribution's revenue requirement.

Q. Does the Company agree with the theory of recovering the cost of the low income program in the revenue requirement?

A. Yes. The final revenue requirement should include the Commission approved cost of the Company's low income program.

Q. Is the dollar amount of the Company's low income program discussed elsewhere in testimony?

A. Yes. The dollar amount of the low income program is discussed in the supplemental direct testimony of Distribution's 2016 Low Income Order Panel.

Q. Please describe the Company's proposal for low income program cost recovery.

A. As described in the direct testimony of the Cost of Service and Rate Design Panel, at page 62, Distribution proposed a reconciliation mechanism to track and refund (or recover) actual low income program costs, which differ from the amount imputed in this case.

Q. Please describe Staff's position, as respects cost recovery for Distribution's low income program.

A. Staff states (at page 75) "due to Staff's

modification of the collection of the low income program from rate design, a reconciliation mechanism is not necessary and will be handled as a deferral."

Q. Did Staff explain why a rate reconciliation mechanism is not necessary?

A. No, Staff's position is only a statement of the affirmative and nothing else. The rationale is not supported with any additional testimony or explanation.

Q. What does the Company recommend?

A. Distribution recommends that the Commission adopt the Company's rate reconciliation mechanism, described above, to provide cost recovery for the Company's low income program. While a deferral mechanism will provide similar results in terms of overall earnings impact on the Company, for changes in the overall costs of the low income program, it will delay the actual recovery or refund of the cost deferral until the Company's next rate case.

Rate Design – Rate Structure – Service Classification No. 13 ("SC 13") Customers

Q. How did Distribution propose to recover the increase assigned to SC 13 customer rate classes?

A. The Company proposed to keep minimum charges at current levels and recover the increase assigned to SC 13 customers through the transportation charges, based on the cost-based minimum charge analysis provided in Exhibit___(COSRD-1), Schedule 5.

Q. Did Staff agree with Distribution's proposal?

A. Yes. Staff described their methodology for developing rates, at pages 85 and 86. Specifically, Staff stated "the minimum charge rates were frozen at current values and all revenue changes were applied through the volumetric block rates."

Q. What did MI recommend, in order to recover the increase assigned to SC 13 customers?

A. MI, at page 15, recommends "that the minimum charges and transportation charges be increased by the same percentage."

Q. Did MI describe a rationale for their recommendation?

A. No.

Q. Did MI perform a cost-based minimum charge analysis, similar to Distribution?

A. No. MI did not provide numerical analyses, analytic studies, or exhibits to support their recommendation.

Q. Are there any other issues regarding Staff's SC 13 rate design calculations?

A. There is a technical issue that was identified through discovery, which is presented below to clarify the record.

Q. Please describe Staff's rate design proposal for SC 13 customers.

A. Generally speaking, Staff agreed with the allocation methodology employed by Distribution, as respects the allocation of the revenue requirement on a percentage basis of non-gas cost revenues. Staff performed one additional calculation, as stated at 86, "we [Staff] grouped the Company's TC 1.1, TC 2, TC 3, TC 4 and TC 4.1 customers together and designed rates based on a revenue allocated dollar amount for each group. We [Staff] spread each

group's portion of the revenue requirement to each TC customer within the group based on a percent of the group's total throughput." Staff's calculation was presented in Exhibit___(SGRP-9).

Q. Does the Company agree with Staff's recommended adjustments presented in Exhibit___(SGRP-9)?

A. No, as described herein. The Company contacted Staff regarding their intent with Exhibit___(SGRP-9) versus what was ultimately presented in this proceeding. Staff and the Company have clarified this issue. Distribution is waiting on an outstanding data request response from Staff. The Company reserves Exhibit___(COSRD-26) for this data request response and reserves the right to address this topic further in testimony or at hearings, if needed. As such, Distribution understands Staff's intent to be the following, as respects Exhibit___(SGRP-9):

- It was not Staff's intent to allocate revenue increases/decreases to negotiated rate customers; negotiated rate customers should have been excluded from Staff's

analysis.

- Staff accidentally calculated eleven months of customer charges for the "TC 4 DMT – N" customer class, where twelve months should have been calculated instead.
- A summary of the Company's proposed rate design allocation was presented in Exhibit___(COSRD-13). In summary, the Company excluded negotiated customers, ensured that the margin for "DMT" and "MMT" customers was the same, and then added in the base cost of gas. The only difference between "DMT" and "MMT," as respects the base cost of gas, is a difference in imbalance charges. The Company confirmed with Staff that their intent was to present a rate design allocation calculation in the same manner as Distribution.

Q. What does the Company recommend?

A. The Company recommends that its proposed rate design allocation for SC 13 customers, as described above

and as outlined in Exhibit___(COSRD-13), be adopted by the Commission.

Rate Design – Rate Structure – Residential and General Customers

Q. Please summarize the position of parties, as respects the minimum charge for residential (Service Classification Nos. 1 and 2) and general customers (Service Classification No. 3).

A. Staff, at pages 79 through 81, recommends holding residential and general minimum charges flat. UIU, at page 6, states "at a minimum, we [UIU] believe customer charges for residential and small commercial customers should not increase." PULP, beginning at page 25, describes two hypothetical scenarios, one with an unchanged minimum charge and another with a reduced minimum charge of $10.00 (both scenarios are residential). Mr. Ford, at page 1, states "the real debate should be about the size of the reduction in the fixed customer charge," even though he cites a preference of abolishing the customer charge (presented as a residential only).

Q. Were residential and general minimum charges

examined during the last rate case filed by the Company?

A. Yes, minimum charges were examined as part of Case-07-G-0141. On December 21, 2007, the Commission issued an Order Establishing Rates for Gas Service ("December 2007 Order"), which generally describes the result of this examination. The Commission's December 2007 Order, at page 48, states "the administrative law judge has recommended that we allow NFG to increase the minimum bill for residential and general service customers by $2.00." On page 49 of the December 2007 Order, the Commission found "that a $2.00 increase in the minimum bills applicable to residential and general service customers is warranted." The Commission also noted "in NFG's next rate proceeding, we will again examine the minimum bill amounts and consider whether any additional, gradual modifications are sufficiently justified at that time on the basis of the customer costs the Company incurs."

Q. Did Distribution present an analysis of minimum charges in this proceeding?

A. Yes. As noted above, Distribution quantified cost-based minimum charges and presented the results of such quantifications in Exhibit___(COSRD-1), Schedule 5.

Q. Please describe the results of Exhibit___(COSRD-1), Schedule 5 for residential and general customers.

A. Exhibit___(COSRD-1), Schedule 5 demonstrates that the monthly customer cost, at proposed rates, would be $31.95 for residential customers and $43.36 for general customers. This Exhibit calculates average customer costs by class, as identified in the NARUC Gas Distribution Rate Design Manual (at page 22): "Customer costs are those operating capital costs found to vary directly with the number of customers served rather than with the amount of utility service supplied. They include the expenses of metering, reading, billing, collecting, and accounting, as well as those costs associated with the capital investment in metering equipment and in customers' service connections. A portion of the costs associated with the distribution system may be included as customer costs."

Q. What minimum charge did Distribution propose in this proceeding for residential and general customers?

A. Distribution proposed a minimum charge of $19.66 for residential customers, an increase of $4.12 from the currently effective minimum charge of $15.54. Distribution proposed a minimum charge of $23.77 for general customers, an increase of $5.91 from the currently effective minimum charge of $17.86. Distribution's proposed minimum charges are based on the Company's quantification of cost-based minimum charges. The Commission should accept the Company's well supported proposal, as it moves rates closer to cost while simultaneously reflecting gradualism the exact ratemaking principle recognized in the Commission's December 2007 Order.

Q. Did Staff justify its recommended position to keep flat the residential and general minimum charges, with any quantitative analysis?

A. No. Staff did not provide numerical analyses, analytic studies, or exhibits to justify flat residential and general minimum charges.

Q. Did Mr. Ford justify his recommended position, as

respects residential and general minimum charges, with quantitative analysis?

A. No. Mr. Ford attempted to justify his recommended position (residential customers only) with analysis. However, the analysis presented was flawed and the result is inconclusive, as will be further discussed later in this rebuttal testimony. Mr. Ford did not provide numerical analyses, analytic studies, or exhibits for general minimum charges.

Q. Please describe Mr. Ford's position, as respects minimum charges.

A. Mr. Ford, at page 1, states he "would prefer to abolish the customer [minimum] charge."

Q. Does Distribution agree with this position.

A. No. Mr. Ford did not provide numerical analyses, analytic studies, or exhibits to support a rationale for abolishing the minimum charge. In fact, Mr. Ford (at page 1) concedes "there are some costs which logically could be assigned equally to every residential customer." Based on Mr. Ford's statements that appear contradictory, there is no dispute that minimum charges should continue in

practice.

Q. Did Mr. Ford attempt to quantify a fixed minimum charge?

A. Yes, despite his statement recommending minimum charges be abolished, this analysis was presented in an Excel spreadsheet titled "Customer Charge Calc.xls."

Q. Does the Company agree with Mr. Ford's analysis?

A. No, this analysis should be rejected by the Commission. The analysis presented is flawed, as it appears to be a work in progress and the result (a minimum charge of $5.58) is inconclusive. A representative example demonstrating this fact occurs in the "Notes" column of Mr. Ford's spreadsheet, where Mr. Ford states "What does this consist of?" when attempting to justify which cost elements should be assigned to Service Classification No. 1 customers. It should also be noted that several cost elements included in Mr. Ford's analysis were improperly omitted or unassigned to Service Classification No. 1 customers, without any explanation or supporting

justification as to why.

Q. Did PULP justify its recommended position, as respects residential and general minimum charges, with quantitative analysis?

A. No. PULP submitted an analysis (residential customers only), which "hypothetically" reduced the minimum charge to $10.00 and then offset that reduction with increases in tail block rates. There are no numerical analyses, analytic studies, exhibits or explanation as to the source of the "hypothetical" $10.00 minimum charge, which is not based on costs incurred by Distribution. PULP did not provide numerical analyses, analytic studies, or exhibits for general minimum charges, despite PULP's characterization (at page 26), that Distribution has "high fixed costs of basic service."

Q. Please describe UIU's minimum charge analysis.

A. UIU's minimum charge analysis was provided in Exhibit___(URP-1), Schedule 2. This exhibit compares the minimum charges calculated by UIU to Distribution's current and proposed minimum charges. UIU states (at page 40) "our cost estimates are

similar to the ones developed by the Company with two important exceptions: we [UIU] have excluded distribution mains and services." It should also be noted that UIU stated "we [UIU] excluded distribution mains for the same reasons presented earlier in the context of the class ECOS [embedded cost of service study] results. We [UIU] excluded services for similar reasons."

Q. Does the Company agree with UIU's minimum charge analysis?

No, this analysis should be rejected by the Commission. As stated above, on a fundamental basis, no customer can be served without a main providing natural gas service to their residence or place of business. There is a fixed cost associated with digging and installing mainlines, running services to those mainlines, and ultimately equipping each customer with a meter set. One of the largest drivers of main and service costs is the number of customers, as the number of customers determines the length of mainline and the number of services that are needed. These costs are incurred

not only when the customer connects to the distribution system for the first time, but also when the mainline servicing the customer, the associated service line, and meter sets are replaced and renewed.

For these reasons, as well as the same reasons explained earlier in the context of cost of service study results, the customer defined portion of mains and all services should reasonably continue to be recovered through the minimum charge. There should be no controversy that service lines represent a fixed customer cost.

Distribution also notes the definition of services (Account 380) from the FERC Uniform System of Accounts for Private Natural Gas Utilities: "(A) This account shall include the cost installed of service pipes and accessories leading to the customers' premises; and (B) A complete service begins with the connection on the main and extends to but does include the connection with the customer's meter."

Q. What are the minimum charges of other major gas

utilities in New York State?

A. Distribution reviewed the currently effective tariffs for major gas utilities, based on publically available information in the New York State Department of Public Service Electronic Tariff System. The results of this review are as follows:

New York State Major Utility Residential Minimum Charges	
Central Hudson Gas & Electric Corporation	$25.00
Consolidated Edison Company of New York, Inc.	$18.60
Keyspan Gas East Corp. d/b/a Brooklyn Union of L.I.	$21.66
New York State Electric & Gas Corporation	$16.30
Niagara Mohawk Power Corporation	$20.35
Orange and Rockland Utilities, Inc.	$20.00
Rochester Gas and Electric Corporation	$16.30
The Brooklyn Union Gas Company	$21.55
Average	**$19.97**

New York State Major Utility General Minimum Charges	
Central Hudson Gas & Electric Corporation	$38.00
Consolidated Edison Company of New York, Inc.	$30.45
Keyspan Gas East Corp. d/b/a Brooklyn Union of L.I.	$37.66
New York State Electric & Gas Corporation	$23.60
Niagara Mohawk Power Corporation	$24.27
Orange and Rockland Utilities, Inc.	$30.00
Rochester Gas and Electric Corporation	$16.30
The Brooklyn Union Gas Company	$37.55
Average	**$29.73**

Q. How does Distribution compare to other major New York State gas utilities, as respects minimum charges?

A. At current rates, Distribution has the lowest residential minimum charge ($15.54) and the second lowest general minimum charge ($17.86), among major New York State gas utilities. As described above in detail, the Company proposed a residential minimum charge of $19.66 and a general minimum charge of $23.77. Distribution's proposed minimum charges would continue to remain below the statewide average of major New York State gas utilities.

Q. What does Distribution recommend?

A. The Company's minimum charge proposal should be adopted by the Commission.

Q. Does UIU note anything additional?

A. Yes. UIU, at page 38, states "higher fixed charges shift cost burdens from larger customers to smaller customers." Of course the opposite is also true. Lower minimum charges shift cost burdens from smaller customers to larger customers.

Q. Does the Company agree with UIU?

A. No.

Q. Has the Panel prepared an exhibit to demonstrate the impact of this on different classes of residential customers?

A. Yes. We have prepared a series of Exhibits similar to Exhibit___(COSRD-19), Schedule 1, discussed above.

Q. Please describe Exhibit___(COSRD-19), Schedule 2.

A. Exhibit___(COSRD-19), Schedule 2 is the same as Exhibit___(COSRD-19), Schedule 1, with the exception that the natural gas bill amounts shown, based on the Company's current rates, have a minimum charge of $0.00. The bill amounts are recovered solely through volumetric rates. This was done by setting the minimum charge to $0.00 and recovering the annual costs of the minimum charge through the volumetric rates by dividing the annual minimum charges by the average annual consumption of a residential customer in our last rate case of approximately 106 Mcf per year. Although presented as an example, this Exhibit does not, in any way, suggest that the Company supports the elimination of

a minimum charge, or a reduced minimum charge.

Exhibit___(COSRD-19), Schedule 1 and Schedule 2 together demonstrate, under a volumetric only rate design for customers using the same amount of gas as the average residential customer, that residential customer bills would not be dramatically different. It should also be noted that Exhibit___(COSRD-19), Schedule 1 and Schedule 2 together demonstrate, that the annual benefit of having access to natural gas has increased from $803.13 to $1,335.62, or 66.3%, from 2008 to 2016, for those customers using the same amount of natural gas as the average residential customer.

Q. Has the Panel calculated the impact on residential customer bills that a volumetric only rate design would have on residential customers that use significantly more than the average residential customer?

A. Yes. We have provided Exhibit___(COSRD-19), Schedule 4 to assess the impact on a residential customer bill for those that would consume 50% more than the average residential customer. This is the

approximate amount that our average LICAAP customer consumes, when compared to the average residential customer.

Q. Please describe Exhibit___(COSRD-19), Schedule 4.

A. Exhibit___(COSRD-19), Schedule 4 is the same as Exhibit___(COSRD-19), Schedule 3, with the exception that the natural gas bill amounts shown, based on the Company's current rates, have a minimum charge of $0.00. The bill amounts are recovered solely through volumetric rates. Although presented as an example, this Exhibit does not, in any way, suggest that the Company supports the elimination of a minimum charge, or a reduced minimum charge.

Q. Please describe Exhibit___(COSRD-19), Schedule 3.

A. Exhibit___(COSRD-19), Schedule 3 provides a summary of the average fuel oil bill, the average Company residential bill, the average bill for LIRA and HRAS customers, and the average bill for LICAAP customers. This summary is based on the twelve months ended March 2008 and the twelve months ended March 2016. Exhibit___(COSRD-19), Schedule 3 assumes that all customer classes use 50% more

natural gas than the average residential customer uses. The natural gas bill amounts shown are based on the Company's delivery and natural gas supply rates in effect during the twelve months ended March 2008 and the twelve months ended March 2016.

Q. What do Exhibit___(COSRD-19), Schedules 3 and 4 demonstrate?

A. Exhibit___(COSRD-19), Schedules 3 and 4 together demonstrate, under a volumetric only rate design for customers using 50% more than the average residential customer, that: (1) residential customer bills in 2016 would **increase significantly** from $965.86 to $1,049.91, or **8.7%**; (2) low income HRAS customer out-of-pocket costs in 2016 would **increase significantly** from $527.36 to $611.41, or **15.9%**; and (3) low income LICAAP customer out-of-pocket costs in 2016 would **increase significantly** from $419.82 to $503.87, or **20.0%**. In summary, under a volumetric only rate design for high usage customers, all high usage customers are significantly penalized simply for the fact that they use more gas than other customers. Of particular interest, is the fact that

large volume low income customers are the customer class that is penalized the most. Specifically, low income payment troubled customers residing in poor housing stock are harmed the most. This demonstrates that there can be serious unintended consequences from failing to quantify and recognize the impact of rate design proposals on customer classes.

Q. Did you conduct a similar analysis for residential customers that consume 50% less than the average customer?

A. Yes.

Q. Please describe Exhibit___(COSRD-19), Schedule 5.

A. Exhibit___(COSRD-19), Schedule 5 provides a summary of the average fuel oil bill, the average Company residential bill, the average bill for LIRA and HRAS customers, and the average bill for LICAAP customers. It should be noted that LIRA, HRAS and LICAAP customers comprise the population of Distribution's low income customers. This summary is based on the twelve months ended March 2008 and the twelve months ended March 2016.

Exhibit__(COSRD-19), Schedule 5 assumes that all customer classes shown use 50% less natural gas than the average residential customer uses. The natural gas bill amounts shown are based on the Company's current rates.

Q. Please describe Exhibit___(COSRD-19), Schedule 6.

A. Exhibit___(COSRD-19), Schedule 6 is the same as Exhibit___(COSRD-19), Schedule 5, with the exception that the natural gas bill amounts shown, based on the Company's current rates, have a minimum charge of $0.00. The bill amounts are recovered solely through volumetric rates. Although presented as an example, this Exhibit does not, in any way, suggest that the Company supports the elimination of a minimum charge, or a reduced minimum charge.

Q. Please describe Exhibit___(COSRD-19), Schedules 5 and 6.

A. Exhibit___(COSRD-19), Schedules 5 and 6 together demonstrate, under a volumetric only rate design for customers using 50% less than the average residential customer, that: (1) residential customer annual bills in 2016 would be significantly reduced

from $513.55 to $401.26, or (21.9%); (2) low income HRAS customers would no longer have an out-of-pocket cost in 2016 (down from an out-of-pocket cost of $75.05); and (3) low income LICAAP customers would continue to have no out-of-pocket cost in 2016. It is important to keep in mind that this is only an example, and that there are no LICAAP customers consuming 50% less than the average residential customer since the LICAAP program is targeted for the most payment troubled low income customer who will very likely consume significantly more than the average customer. In summary, for this example, under a volumetric only rate design for low usage customers, low income customers would not be expected to pay anything for natural gas service and residential, non-low income customers would benefit significantly.

Q. Do you have any evidence regarding low income customer's consumption patterns based on household size?

A. Yes. The Company is able to track the consumption patterns of our LICAAP customers, based on household

size, since household size in our existing LICAAP program, determines the level of discount that a customer would qualify for. Exhibit___(COSRD-27) provides a graph demonstrating usage by household size. Not surprisingly, as household size increases, so does natural gas consumption.

Q. Do you have any additional evidence comparing low income customer usage to average residential customers?

A. Yes. Exhibit___(COSRD-28) provides a summary of number of customers, percentage of customers, and average usage in Mcf for the twelve months ended April 2016. This summary is further segmented into: residential sales; residential choice; elderly, blind and disabled payment-troubled residential assistance ("EBD-PTRA"); HRAS sales; HRAS choice; and LICAAP. This summary provides two representative zip codes from the Company's service territory, 14215 and 14051, as well as a summation of all residential customers for comparability purposes. 14215 is an example of a low income zip

code, with a median household income of $31,874.[3] 14051 is an example of a high income zip code, with a median household income of $106,710.[4]

Exhibit___(COSRD-28) demonstrates that the average usage in Mcf for single unit residential homes is 91.2 Mcf. This compares to 110.3 Mcf in 14215 and 104.8 Mcf in 14051. This Exhibit confirms that higher income zip codes have lower concentrations of low income customers (i.e., 3.5% of single unit residential in 14051) when compared to lower income zip codes (i.e., 45.9% of single unit residential in 14215).

Exhibit___(COSRD-28) also demonstrates that low income customers (EBD-PTRA, HRAS sales, HRAS choice and LICAAP) in 14215 have a higher average usage in Mcf, when compared to all residential low income customers. Specifically, single unit residential in 14215 is 112.8 Mcf for EBD-PTRA, 110.5 Mcf for HRAS sales, 121.7 Mcf for HRAS choice, and 131.7 Mcf for LICAAP. This compares to 112.1 Mcf for EBD-PTRA,

[3] United States Census Bureau, 2010 – 2014 American Community Survey, Table ZCTA5.
[4] Id.

88.7 Mcf for HRAS sales, 95.2 Mcf for HRAS choice, and 121.5 Mcf for LICAAP, for single unit residential in all zip codes within Distribution's service territory. Finally, this Exhibit confirms that choice customers are using more than sales customers in all instances, but significantly more in the low income sector.

Q. Please describe Exhibit___(COSRD-29), the zip code study conducted by Distribution.

Exhibit___(COSRD-29) provides an analysis of consumption characteristics of customers based on median income and age of home, as previously presented by Mr. Meinl in Case 07-G-0141. The approach used was to compare United States Census Bureau information by zip code to volumetric consumption for residential customers by zip code.

A. The zip code study analyzed the consumption characteristics of residential customers in the major communities served by the Company. The study looked at the overall consumption characteristics for zip codes with approximately 1,000 or more residential customers being served.

Exhibit___(COSRD-29), Page 1, provides a graphical summary of that analysis. Page 1 of Exhibit___(COSRD-29) provides the average consumption per residential account for each zip code in the Company's service territory sorted from lowest income zip code on the far left of the x-axis of the graph to highest income zip code on the far right of the graph. The y-axis represents the average residential usage per account for each zip code on the graph. Bracketed at the top of the graph is the lowest income quartile of the zip codes analyzed and the highest income zip codes analyzed. The dashed line running through the middle of the graph provides the average usage for all residential accounts for the zip codes analyzed. As can be seen from the graph, the three zip codes with the greatest average residential consumption per account are in the lowest income quartile. Further, five out of the seven zip codes with the highest average consumption per residential account are in the lowest income quartile. The other two zip codes with the higher consuming average residential

accounts are in lower middle income zip codes of the Company's New York service territory.

Included on the graph is a trend line of average volume per account. That trend line demonstrates the decline in residential consumption per account as income increases.

Q. Please comment on the zip code with the lowest usage per account.

A. This zip code has a high proportion of seasonal homes (58%) compared to the proportion of homes in the counties served by the Company (2.5%). It is likely that a number of Company accounts for this zip code are seasonal homes. Page 2 of Exhibit___(COSRD-29) identifies the two zip codes with a significant percentage of seasonal homes as well as the zip codes that are served by a municipal electric utility that receives an allocation of low cost New York Power Authority ("NYPA") power. The two zip codes with a significant percentage of seasonal homes are among the lowest consuming average residential accounts in the Company's New York service territory. Because seasonal homes are

likely vacant for a portion of the year, their consumption is likely to be lower than non-seasonal homes. This observation is consistent with the overall observation that low income customers are likely to use more gas than higher income customers since low income customers typically would not own seasonal homes.

Also, the three zip codes with the lowest average residential consumption per account are in communities served by municipal electric utilities that receive an allocation of low cost NYPA power. The percentage of homes that use electricity for primary heat in these three zip codes ranges from 18% to 29%, or from two to three times the primary heating saturation for electricity in the New York counties served by the Company. Residential customers receiving the benefits of allocated low cost NYPA power receive a significant reduction in their energy bills related to their electric consumption. There is little justification for these areas of the Company's service territory to achieve additional benefits associated with the

disproportionate recovery of fixed natural gas delivery costs through volumetric natural gas delivery rates.

Q. What does Exhibit___(COSRD-29), Page 3 demonstrate?

A. Exhibit___(COSRD-29), Page 3 provides a likely explanation for the reason why this trend of lower consumption per account as income increases. Exhibit___(COSRD-29), Page 3 adds an analysis of the percentage of homes built after 1980 by zip code. This is important since significant changes in housing stock building codes and furnace efficiencies were established post-1980. The y-axis on the right hand side of the graph provides the scale for the percentage of homes built after 1980. The bars on the graph provide the percent of homes built after 1980 for each zip code analyzed. The dotted line provides the average percentage of homes built post 1980.

As can be seen from the graph, for the lowest income quartile, all of the zip codes exhibit percentages of housing stock built after 1980 that are below the average percentage for all zip codes

analyzed. For the highest income quartile, all but two zip codes have a higher percentage of housing stock built after 1980 than the average for the zip codes analyzed.

This result is not surprising. One wouldn't expect that low income customers would have the resources to afford to build newer homes. Newer homes, of course, have newer appliances (including more efficient furnaces). The fact that higher income households are more likely to be in newer housing stock than lower income households likely explains the fact that higher income zip codes tend to consume less natural gas per account than lower income zip codes.

Q. Do energy efficiency programs provide the potential for reductions in the bills of lower income customers?

A. While all customers can benefit from utilizing natural gas efficiently, lower income customers have the greatest potential for usage reduction associated with energy efficiency initiatives, since they tend to use greater amounts of natural gas.

Q. Does the Panel believe that the parties aware of the consumption characteristics of customers on the Company's system?

A. No. This was described above in the General Service Territory Overview section of this rebuttal testimony, as well as in Exhibit___(COSRD-18), Schedules 1 through 4.

PULP - Low Income Housing Cost Burden

Q. Please describe PULP's analysis of housing cost burdens on low income customers.

A. PULP, at page 10, cites "numerous indicators of long term and increasing unaffordability [sic] among the Company's customers whose households receive less than $35,000."

Q. Did PULP use United States Census Bureau data to support its position?

A. Yes. PULP, at page 10, stated "housing cost burden" data was analyzed.

Q. Is this an accurate representation of the affordability of natural gas bills?

A. No. According to the United States Census Bureau, "housing cost burden" data includes "mortgage

payments, rent payments, condominium and other fees, real estate taxes, premiums for home owners insurance, installment loan payments [mobile homes], site rent [mobile homes], license and registration fees [mobile homes], personal property taxes [mobile homes], electricity costs, gas costs, other fuel costs, water and sewer costs." With the variety and number of non-energy related costs included in this number, it is not a meaningful "yardstick" of the affordability of natural gas bills.

During discovery, PULP responded to a data request from Distribution, affirming that the Company does not control customer costs associated with buying or leasing a home, apartment, or any other type of housing unit. A copy of this data request response is provided as Exhibit___(COSRD-34).

Q. Have natural gas prices added to the housing cost burden for low income customers?

A. No. It is clear from Exhibit___(COSRD-19) that the dramatic decline in natural gas prices have not added to the housing cost burden of low income

customers. Quite the opposite - natural gas prices have obviously provided a mitigating effect on housing cost burdens cited by Mr. Yates. As mentioned previously, the annual benefit of having access to natural gas has increased from $803.13 to $1,335.62, or 66.3%, from 2008 to 2016, for those customers using the same amount of natural gas as the average residential customer.

Q. Please describe PULP's HEAP discount recommendation.

A. PULP, at pages 7, 16 and 17, recommends adopting "the eight-month discount for HEAP recipient customers as originally proposed in the Company's Customer Service Panel testimony, should the Company's Low Income Order Petition not be answered by the effective date of the order in this proceeding."

Q. Where will this be addressed in Distribution's rebuttal testimony?

A. This issue will be addressed in the rebuttal testimony of the Company's Customer Service Panel.

Price Signal for Conservation

Q. Please summarize the position of parties, as respects tail block rate design.

A. UIU states (at page 41) that "improved price signals can be achieved by recovering more of the Company's revenues through the tail block." PULP states (at page 29) that "the stakes for the Company's low income customers in this regard are very high," that "it's almost certain that they [low income customers] would be disproportionally harmed," and that the "magnitude of the increase is bad enough." Mr. Ford states (at page 1) that fixed fees for residential customers "result in higher costs per CCF for low usage customers." Staff (at pages 79 through 81) recommends an equal percentage allocation across the middle and tail block rates, for both residential and general customers.

Q. Does Distribution agree with the position of any of the other parties?

A. No. As demonstrated above in this testimony, a higher tail block rate design would: (1) significantly benefit low usage non-low income

residential customers, (2) entirely subsidize the gas bill for low usage low income residential customers, (3) have a de minimus impact on all average usage customers, regardless of their income status, (4) increase the costs on all high usage customers, and (5) severely penalize most of all the most payment troubled low income customers, residing in poor housing stock.

Therefore, despite UIU's claim (at page 41) that improved price signals would not be afforded to customers and that low income customers would be harmed the most by the Company's rate design, the opposite is true - the solution proposed by UIU would actually harm the low income customer class even more.

Finally, Mr. Ford's statement (at page 1) has been proven to be factually incorrect.

Q. PULP states (at pages 26 and 27) that "rate designs based on high fixed basic service charges and flat and declining block rates for delivery service create affordability problems for low income customers." Is this factually correct, based on the

foregoing analysis?

A. No, based on the foregoing analysis, this is factually incorrect.

Q. Please summarize the position of parties, as respects energy conservation price signals for residential customers.

A. UIU states (at page 39) "in our [UIU] view, some aspects of the Company's current rate structure do not provide the right price signals to encourage energy efficiency and do not sufficiently incentivize customers to invest in energy efficiency." UIU continues to state (at page 41) that "improved price signals can be achieved by recovering more of the Company's revenues through the tail block" and that such an approach will "provide stronger incentives for customers to conserve energy." PULP (at pages 26 and 27) claims that rate designs based on high fixed basic service charges and flat declining block rates for delivery service "act as a disincentive to conservation and energy efficiency initiatives." PULP, beginning at page 25, describes two hypothetical scenarios, one

with an unchanged minimum charge and another with a minimum charge of $10.00, which according to PULP (at page 30) would "encourage energy conservation and efficiency." Mr. Ford (at page 1) states "fixed fees for residential customers penalize and provide a disincentive for energy conservation."

Q. Do the parties recognize that there are practical limits to how much a customer may be able to conserve?

A. Yes. All of the parties confirmed during discovery that there are practical limits to how much a customer may be able to conserve. Copies of the data request responses supporting this fact from Staff, UIU, and PULP are provided as Exhibit___(COSRD-18), Schedule 1, 2 and 3, respectively (question number 150 for Staff and question number 15 for UIU and PULP).

Q. Is it irrational for a customer in western New York to choose to turn up their thermostat and ignore price signals to conserve, as recommended by some of the parties in this case?

A. No. While setting back a thermostat would result in

slightly less usage, it is a limited solution from a health and safety perspective. Exhibit___(COSRD-30) provides an article published by the Erie Times, demonstrating the limited nature of this solution. Mr. Winston, a local plumber at 1, states "if you have the thermostat set at 62 or 65 right now, you're crazy." He further states "you'll save $5 on gas and spend $500 on plumbing repairs." Simply put, there is a practical limit even when it comes to employing conservation in practice. The Erie Times article confirms this (at page 2): "when it gets as cold as this [January], a lot of furnaces won't keep up with it. They might only get to 68 degrees even though they're set to 72 [degrees]."

Q. What does Distribution conclude, as respects options available to high usage low income customers?

A. These customers have very few options available, even with a tail block rate structure that is supposed to "motivate conservation," especially if it is economically rational for low income customers to recognize the "plumbing repair" price signal and choose the lower cost alternative to frozen pipe

repairs.

Q. How does the Company help low income customers increase their access to no cost weatherization and equipment replacements?

A. As described in the direct testimony of the Energy Services Panel, Distribution's Low Income Usage Reduction Program ("LIURP") is a weatherization program designed specifically for low income customers. Distribution provides participants with a heating system review, an energy audit, weatherization measures and consumer education. The program design is consistent with, and is being administered in conjunction with the New York State Energy Research and Development Authority's ("NYSERDA") EmPower New York program. The main goal of LIURP is to conserve energy, reduce residential energy bills, and improve the health, safety, and comfort levels for participating households.

Beginning January 1, 2016, as part of LIURP, Distribution has earmarked $250,000 of incentives and services funding per year for a low income health and safety furnace replacement initiative.

This initiative is modeled after the HEAP Heating Equipment Repair and Replacement Program ("HERR"), which historically exhausts funding during the middle of the HEAP season. To the extent that HEAP eligible customers contact Distribution directly about old and inefficient heating equipment, malfunctioning heating equipment, or potential safety concerns, especially during the winter heating season, the Company would be able to have a contractor immediately install a high efficiency furnace and programmable thermostat at no cost to the customer. This furnace replacement initiative: (1) augments existing limited health and safety protocols currently in place as part of LIURP and EmPower, (2) supports the primary goal of LIURP, (3) helps prevent emergency situations for customers due to an underfunded portion of HEAP programming or a general lack of available options, and (4) produces energy savings by replacing legacy heating equipment with high efficiency heating equipment that low income customers may not otherwise be able to afford.

Q. What are the results of LIURP, with respect to number of customer participants and the dollar amount of weatherization services?

A. Since the inception of LIURP in September 2007, and as of December 31, 2015, Distribution has completed more than 7,100 weatherization jobs. This corresponds to approximately $26.6 million of incentives provided at no cost to Distribution's low income customers. Consistent with Commission policy objectives, LIURP produces energy savings for customers, the value of which exceed program expenditures.

Exhibit___(COSRD-31) provides a map of natural gas and electric low income weatherization jobs completed throughout New York State, from the Company and NYSERDA's 2014 joint evaluation work. The map demonstrates that Distribution's coordinated effort with NYSERDA has been highly effective: 68% of all of New York State's low income EEPS weatherization work was completed in the Company's service territory. This is notable, as only 3% of weatherization jobs were completed in New York City.

It should be noted also that varying pie slice colors in the map represent the distribution of work among contractors. Not only is the Company's coordinated approach working effectively, but it is resulting in an even distribution of work amongst multiple contractors. Distribution looks forward to continuing its collaborative relationship with NYSERDA in the future, especially in the low income sector and as Clean Energy Fund opportunities present themselves prospectively. Coordinating activities to provide conservation services to low income customers, between the Company and NYSERDA, is the most effective way for low income customers to receive the benefits of conservation.

Q. What does PULP ultimately recommend, as respects energy conservation price signals for residential customers?

A. PULP (at page 8) recommends "alternative rate designs should be the subject of a collaborative study among the parties in this proceeding."

Q. Does the Company agree with PULP?

A. No, this recommendation should be rejected by the

Commission. A collaborative study simply serves as a "re-opener" of the rates being examined in this proceeding. The Company presented the results of a significant study on alternative rate designs, as part of the rebuttal testimony presented in this panel. In addition, PULP's claim at 29, that they "lack much of the information needed" is unfounded, especially since all parties participated in an extensive discovery process as part of this proceeding.

Q. Does the Company agree with PULP's two hypothetical scenarios used to justify a future collaborative?

A. No. PULP's hypothetical scenarios have no value in establishing rates, since the hypothetical scenarios do not consider annual consumption of the rate year. The Company also disagrees with PULP's two hypothetical scenarios for several reasons described in the "Rate Design – Rate Structure – Residential and General Customers" section of this rebuttal testimony.

UIU – Seasonal Rate Structure

Q. Does UIU make any additional recommendations?

A. Yes. UIU (at page 42) recommends "introducing a seasonal rate structure, which retains a somewhat more steeply declining block rate structure during the months of January through March, while flattening rates to a greater degree during other months."

Q. Is UIU's recommendation supported, quantitatively?

A. No. UIU did not provide numerical analyses, analytic studies, or exhibits to substantiate their recommendation. As such, it is entirely opinion-based.

Q. Does the Company agree with UIU's recommendation?

A. No. On the most basic level, since the recommendation is not supported quantitatively, there is nothing on the record to consider. UIU's proposal would provide subsidies to seasonal customers (a phenomenon described above in detail), while continuing to harm low income payment troubled customers, residing in poor housing stock, during the middle of the winter heating season.

Q. What does the Company recommend?

A. Distribution recommends that its proposed rate design mix of minimum charges and tail block rates, unmodified, be adopted by the Commission.

Staff – Leak Prone Pipe ("LPP") Mechanism

Q. Does Staff's Gas Rates Panel agree with the Company's proposed system modernization surcharge mechanism?

A. Yes, however, with a number of modifications.

Q. Has the Staff Gas Rates Panel identified their modifications?

A. Yes. Staff has identified their modifications in their direct testimony. In addition, Staff has further clarified their intended modifications informally. As such, Distribution is waiting on an outstanding data request response from Staff. The Company reserves Exhibit___(COSRD-32) for this data request response and reserves the right to address this topic further in testimony or at hearings, if needed.

Q. Please itemize the differences between the Company's and Staff's proposals.

A. Staff is generally accepting the Company's surcharge mechanism with the following modifications:

1) The method would employ the pre-tax rate of return, depreciation rates, property taxes and uncollectible rates as approved by the Commission. The Company is in agreement that the Commission approved cost elements listed above should be used in the calculation.

2) Staff is proposing that the property tax impact associated with the additional pipeline mileage replaced be lagged for two years to reflect the timing of the property tax assessment. The Company can agree with Staff's recommendation regarding the treatment of property tax if it is agreed that the surcharge mechanism should be applied during periods beyond the rate year, and at least until new rates are established in the Company's next base rate case.

3) Staff is recommending that the surcharge mechanism be in effect over a pre-established time period. The Company does not agree with this proposal since it adds uncertainty to the

ability of Distribution to recover the costs associated with the Company accelerating improvements of its system beyond the mileage amounts assumed in the capital budget for the rate year. The Company proposes that the surcharge mechanism would continue beyond the rate year and at least until new rates are established in the Company's next base rate case. The continuation of the surcharge mechanism is a reasonable proposal. The Company will be faced with continuing rate pressure beyond the rate year since it is intending to replace 105 miles of leak prone pipe in the rate year and beyond. Any replacement mileage, up to 105 miles, installed after the rate year will have a negative effect on the Company's overall earnings, all else held equal. The Company would only be able to achieve a reasonable return through cost savings or filing another base rate case.

4) Staff has proposed that the cost per mile for the rate year would be capped at $398,351 per

mile. The Company disagrees with this cost cap since it significantly underestimates the cost per mile, which the Company projected in its capital budget of $847,300 per mile.

5) Staff is proposing an additional two basis point per mile incentive, capped at ten basis points or five miles, to be in place for only one year. The Company agrees that Staff's two basis point on equity incentive, per mile of additional system replacement above the 105 mile target, is reasonable. However, the Company disagrees that there should be a cap or a one year limit on the proposal. It has been clearly established in Case 15-G-0151 that the Commission desires an acceleration of the replacement of leak prone pipe. A limit on the number of miles to which an incentive would apply, as well as a one year time limit on the incentive application, runs counter to the otherwise clear signal that the Commission desires; that leak prone pipe be removed as quickly as practical. As mentioned previously,

any replacement mileage up to 105 miles installed after the rate year will have a negative effect on the Company's earnings. The incentive to go beyond 105 miles after the rate year should not be removed. If anything, given the uncompensated 105 mile base mileage replacement, the incentive would be more appropriately **increased**.

6) Staff is also recommending that the Company's proposal to first recover the costs of the accelerated leak prone pipe mechanism from the ratepayer's portion of offsystem sales and capacity release be rejected and instead be recovered through a surcharge. The Company does not oppose this suggested modification.

7) Staff also recommends that the revenues to be recovered through the surcharge be allocated to the Company's service classification rates based on delivery revenues and then specific rates for each service classification rate schedule would be developed. The Company does not oppose this recommendation since it is

consistent with the Company's increase allocation proposed in this proceeding.

Q. Staff opposes the Company's proposed reconciliation mechanisms for other safety or regulatory-related expenses incremental to the costs of programs and initiatives recognized in rate year expenses. Is Staff's proposal reasonable?

A. No, it is not. Staff assumes that the Company is proposing that these costs would be allowed recovery without Commission approval. Exhibit___(COSRD-33) is a copy of the proposed tariff leaf implementing the System Modernization Tracker. As is identified on the section on qualified costs, only costs authorized by the Commission would be allowed recovery.

PULP – Two to Four Family Dwellings

Q. Please describe PULP's position, as respects two-to-four family dwellings and non-residential customers included in service classification 1.

A. PULP (at pages 7 and 25) recommends the Company "create one or more new service classes for the accounts of master metered two-to-four family

dwellings and those non-residential customers currently included in Service Class 1."

Q. As of May 5, 2016, how many residential customers did Distribution have?

A. Exhibit___(COSRD-28) provides the number of residential accounts with at least twelve months of continuous consumption by number of residential units.

Q. Please describe how the total number of residential customers is segmented into single family unit housing, two family unit housing, and three and four family unit housing.

A. According to Exhibit___(COSRD-28), of the 405,489 total residential customers: 403,141 or 99.4% represent single family unit housing; 1,489 or 0.4% represent two family unit housing; and 859 or 0.2% represent three and four family unit housing.

Q. Does it make sense to split two family unit housing and three and four family unit housing into its own service classification, as PULP recommends?

A. No. The number of two family unit houses and three and four family unit houses is de minimus. As

described in the Report on Natural Gas Efficiency Goals, issues in downstate New York are not prevalent in the Company's service territory.

Q. Would it be administratively burdensome to implement segregated service classifications for two family unit houses and three and four family unit houses?

A. Yes. Distribution would have to frequently visit the inside of customer homes (both initially and on an on-going basis as home improvement projects and construction projects are completed), in order to verify that customers are assigned the proper service classification. In addition, the Company would need to actively monitor and verify when customers move in and out of housing units, in order calculate bills properly.

A practical example of the difficulty in the Company's service territory are "telescope" homes. This is described (with a number of pictures), in an August 2015 article published by Arch Daily,

referenced below.[5] Telescope homes provide an example of how it would be virtually impossible from either the outside or the inside of the housing structure, to determine how many housing units exist and are occupied.

It should be noted that PULP (at page 19) states "it has been perfectly logical to include master metered two-to-four family dwellings in SC1."

Q. Please describe PULP's analysis comparing a single family residence to a multi-family dwelling with four households.

A. PULP (at pages 19 through 21) submitted Table 2 with their testimony. Table 2 attempts to price out the bill of a single family residence, as well as the bill of a multi-family dwelling with four households, all of whom consume the same volume of gas monthly. PULP (at page 21) states "the total usage of the individual tenants in the multi-family dwelling is combined (89.8 * 4 Ccf)."

[5]The August 2015 Arch Daily article is available at the following location: http://www.archdaily.com/771613/the-rise-and-fall-of-buffalos-curious-telescope-houses.

Q. Does Distribution agree with PULP's analysis?

A. No. PULP's analysis is flawed, as it fails to take into account shared walls that are not exposed to weather, common hot water tank water, or other efficiencies that would be present in multi-family buildings (e.g., shared boiler or furnace).

Q. Are customers precluded from participating in the Company's low income programs or energy efficiency initiatives if they live in two family unit housing or three and four family unit housing?

A. No. All qualified customers are equally encouraged to participate in the Company's low income programs or energy efficiency initiatives. Including all residential customers in a residential service classification does not "impede policy imperatives," contrary to PULP's claim (at pages 21 to 23).

Q. Please describe PULP's position, as respects non-residential customers migrating from Service Classification No. 3 to Service Classification No. 1.

A. PULP states (at page 25) "a growing mix of residential and non-residential customers within the

SC1 class is not likely to be compatible with efforts to update rate designs that are logical, just and reasonable for all the members of the SC1 class."

Q. Please describe Public Service Law §76.

A. Our counsel advises us that Public Service Law §76 states the following: "No gas corporation, electric corporation or municipality shall, directly or indirectly, charge, demand, collect or receive from any post or hall owned or leased by a not-for-profit corporation that is a veterans' organization, or corporation or association organized and conducted in good faith for religious purposes, including the operation by such corporation or association of a school, notwithstanding that secular subjects are taught at such school, or from a community residence as defined in subdivision twenty-eight, twenty-eight-a or twenty-eight-b of section 1.03 of the mental hygiene law, provided, however, that such residence shall be operated by a not-for-profit corporation and if supervisory staff is on site on a twenty-four hour per day basis, that the residence

provides living accommodations for fourteen or fewer residents, a rate, regardless of the type of service offered, for any gas or electric service utilized exclusively in connection with such veteran organization or for such religious purposes or utilized exclusively at such community residence greater than the rates or charges charged, demanded, collected or received by such gas corporation, electric corporation or municipality from domestic consumers receiving single-phase service within the same village, town or municipality."

Q. Would it be administratively burdensome to implement a segregated service classification for non-residential customers receiving a residential rate?

A. Yes. As described above, our counsel advises that non-residential customers are receiving a residential rate due to Public Service Law §76. Establishing a new service classification for roughly 2,000 customers, in order to charge those customers precisely the **same rate**, does not make sense, is administratively burdensome and provides no benefit.

Regulatory Audits

Q. Mr. Meinl, have you reviewed Mr. Crahen's rebuttal testimony on recently completed and on-going New York regulatory audits?

A. Yes.

Q. Mr. Meinl, please describe the result of your review of Mr. Crahen's rebuttal testimony.

A. Mr. Crahen's rebuttal testimony, especially the description of results in Case 13-M-0449 validates and confirms the direct testimony I submitted in this proceeding. Particularly, it provides a rational explanation for how the Company was able to operate its system in a safe, reliable, effective and efficient manner while margins were decreasing by 0.5% on a compounded annual basis, while the statewide average growth in margins was 3.5% on a compounded annual basis. It further supports the recommendation that the rates established in this case reflect a ROE at the high end of the range of reasonable ROE's.

Closing

Q. Does this conclude your rebuttal testimony?

A. Yes, at this time.

BY MR. NICKSON: (Cont'g.)

Q. Panel, are you also sponsoring 17 exhibits to your direct testimony which were identified as COSRD - 1 through COSRD - 17 and 18 additional documents which represent the panel's work papers for those exhibits?

A. (Meinl) Yes.

Q. And are you also sponsoring 17 exhibits to your rebuttal testimony which were identified as COSRD 18 through COSRD 34?

A. Yes.

Q. And were those documents prepared by you and under your supervision?

A. Yes, they were.

Q. And do you have any changes to those documents?

A. No.

MR. NICKSON: Your Honor, I ask that these documents be marked for identification.

A.L.J. LECAKES: So we'll go slow on this one. So for COSRD 1 that will be marked as Exhibit 201. For COSRD 2 Exhibit 202, COSRD 3 Exhibit 203, COSRD 4 Exhibit 204, COSRD 5, 205, COSRD 6, 206, COSRD 7 Exhibit 207, COSRD 8 Exhibit 208, COSRD 9 Exhibit 209, COSRD 10

Exhibit 210, COSRD 11 Exhibit 211, COSRD 12 Exhibit 212, COSRD 13 Exhibit 213, COSRD 14 Exhibit 214, COSRD 15 Exhibit 215, COSRD 16 Exhibit 216, COSRD 17 Exhibit 217.

I also have listed after that submitted with the initial testimony ones that were called -- exhibits that have been listed as work papers for Exhibit COSRD 1, work papers for Exhibit COSRD 2 and work papers for Exhibit COSRD 3. Are those intended to be introduced separately as exhibits?

MR. NICKSON: Yes, your Honor.

A.L.J. LECAKES: Okay. So that will be work papers for COSRD 1 will be Exhibit 218. Work papers for Exhibit COSRD 2 will be 219. Work papers for Exhibit COSRD 3 will be 220.

Mr. Nickson, was the foundation laid for those when you did your introduction of the exhibits?

MR. NICKSON: I believe so, yes.

A.L.J. LECAKES: Okay. Thank you. So then Exhibit Work Paper General Plant Allocation Exhibit 221, Work Paper Structures Allocation Exhibit 222, Work Paper -- well, Labor Allocation 223, Work Paper A.G. -- A. and G. Allocation 224, Work Paper A. and G. -- I'm sorry, Work Paper -- on page 4 and 5 of the exhibit list that I passed out -- oh, I see. I'm sorry.

So Exhibit 224 is -- is rather marked as Work Paper for the Consumer Services. The Work Paper for the A. and G. Allocation is Exhibit 225. The Work Paper for the Mains and Customer Demand is Exhibit 226. The Work Paper for the Cogeneration Allocation is Exhibit 227. The Work Paper for the Mains 4-inch Allocation is 228. The Work Paper for the Services Allocation is 229.

The Work Paper for the Meters Allocation is 230. The Work Paper for the Industrial M. and R. Allocation is Exhibit 231. The Work Paper for Uncollectibles is Exhibit 232. Work Paper for the Customer Service Allocation is Exhibit 233. The Work Paper for the Sales promotion is Exhibit 234. And the Work Papers for Exhibit COSRD - 8 is Exhibit 235.

And is that all of the exhibits that I cover?

MR. NICKSON: Those were all of the exhibits that were attached to direct testimony. There's also I believe it's 17 attached to the rebuttal testimony.

A.L.J. LECAKES: Right. Okay. Starting with COSRD 18 I believe we're at Exhibit 236. COSRD 19, 237. COSRD 20, 238. COSRD 21, 239. COSRD 22, 240. COSRD 23, 241. COSRD 24, 242. COSRD 25, 243. COSRD 26, 244. COSRD 27, 245. COSRD 28, 246. COSRD 29,

247. COSRD 30 is 248. COSRD 31 is 249. COSRD 32 is 250. COSRD 33 is Exhibit 251. And COSRD 34 is Exhibit 252.

Does that take care of all of the exhibits? I believe it does on my exhibit list, but --.

MR. NICKSON: Yes, your Honor. I just want to note that the exhibits that were just identified as Exhibit 244 which was the COSRD 26 and Exhibit 250 which was COSRD 32 -- those documents are on the CDs that were provided to your Honor and the court reporter are the revised versions that were circulated to the parties on September 30th.

A.L.J. LECAKES: Okay. Great. For the purposes of the hearing transcript, the exhibits are not being placed there. They're being placed on DMM, so the court reporter needs to do nothing with those exhibits. I'll make sure the corrected exhibits get on to DMM.

MR. NICKSON: Thank you.

A.L.J. LECAKES: Thank you.

MR. NICKSON: And the panel's ready for cross examination.

A.L.J. LECAKES: Thank you. Does staff have any cross examination for this panel? I don't have any listed but.

MR. FAVREAU: None.

A.L.J. LECAKES: Thank you. I have UIU, PULP and MI I believe as the 3 that have indicated cross prior to this hearing for this panel. Has there been agreement among the intervenors as to which parties will go first?

MR. FORD: Your Honor, could I ask a few questions after you --?

A.L.J. LECAKES: Absolutely, Mr. Ford. I forgot, yes. Mr. Ford did ask me for permission. We'll let you go last, Mr. Ford, so you can see if other parties have asked questions similar to the ones that you want to ask. And -- and if they've answered your questions prior to that.

MR. FORD: We just had some informal discussions. I haven't had it with PULP but I -- I think the order you mentioned is fine with -- with me, your Honor.

MS. JORGENSEN: I -- I think -- I think if I recall I had sent you an e-mail and I also spoke about it. I thought the best order would be in order of preferred time. So you already had asked the most amount of time then you had followed and then I would follow.

MR. ZIMMERMAN: Oh, okay. That's fine with me too.

A.L.J. LECAKES: That works for me. Okay. Mr. Zimmerman, Ms. O'Hare.

MR. ZIMMERMAN: Thank you, your Honor. And thanks panel for being here this morning especially, Mr. Crahen.

THE WITNESS: (Crahen) Thank you.

CROSS EXAMINATION

BY MR. ZIMMERMAN:

Q. So I know you want to get out of here, so we'll try to move through things quickly. I'd like to start please with your rebuttal testimony at page 8, line 21. We have copies of this if anyone needs any.

So starting on page 21 -- or excuse me, starting on line 21 you wrote, however, given the initial testimony of many of the intervening parties it's useful to review the company service territory relative to downstate New York service territories more thoroughly, is that right?

A. (Meinl) Yes.

Q. Okay.

A. (Crahen) Yes.

Q. And then further down on that page,

page 9, line 7 to 9, you make reference to, quote, wide ranging difference between the service territories and geographical areas. For example, comparing and contrasting Metro New York City to the rural widespread regions found in central and western, New York, correct?

A. Yes.

Q. Okay. So I'd like to ask you about some of those distinctions. Can you please take a look at the final report on natural gas efficiency goals that you make reference to on page 9, line 16 of your testimony and is Exhibit -- attached to your testimony as Exhibit -- excuse me, we'll get that Exhibit number? I believe that's Exhibit 20. COSRD 20 which has been marked for identification as -- not really sure where that went.

Here it is. So we're looking at COSRD 20, report on natural gas efficiency goals?

A. Correct. Yes.

Q. So I'd like to ask you a few of the items in here. Starting on page 5 of Schedule 1. Table 1, this looks like it shows the percentage of housing with gas as a principal heating fuel, is that correct?

A. Yes.

Q. And the totals -- looks like Rochester is 72%, Buffalo 87% and New York, New York is 39% the

percentage of homes using gas as their main source of heating fuel?

A. Yes.

Q. Is that right? Okay. So this shows that Rochester and Buffalo are disparate from New York City, is that right, with respect to that figure?

A. With respect to this table, yes.

Q. Okay. Next table, Table 2 on page 7 shows percentage of owner occupied housing units. And I see Rochester the total is 70% and Buffalo is 68%? Is that right?

A. Yes.

Q. So just 2% different? Table 3, we're looking at the percentage of households in 1 to 4 unit structures and mobile homes? And, again, that appears to indicate that -- that Rochester and Buffalo are 2% off, 90 and 92% respectively, is that right?

A. Yes.

Q. And move to the next page, Table 4, percentage of households using forced air for heating. It appears that Rochester and Buffalo are 4% apart, 77 and 73% respectively, is that right?

A. Yes.

Q. So these metrics -- at least with

respect to these metrics indicate a number of similarities between Rochester and Buffalo, is that fair to say?

A. Yes.

Q. Okay. How about weather? Can we turn to Exhibit COSRD 21? I'm on Schedule 2 page 1 of 8.

So this schedule by its title indicates heating degree days from 1981 to 2010, is that correct?

A. Yes, that's correct.

Q. And, oh excuse me, let's turn please to page 5 of 8 of that schedule which includes Buffalo and Rochester. Now in the annual column on far right, how many heating degree days are indicated for Buffalo?

A. 66 80. Oh, sorry. 66 17.

Q. Yeah. And how many heating degree days are indicated for Rochester?

A. 66 46.

Q. All right. And that's a -- by my math that's a difference of 29, is that right? That sound right to you?

A. 66 80 less 66 46. Or sorry, 66 17 plus the 66 46? Yes?

Q. Yeah. So but in general they're -- they're very close, is that fair to say?

A. (Meinl) It's cold in both places.

Q. Yeah. So how does Rochester Gas and Electric classify their distribution mains between customer related and demand related?

A. I don't know.

Q. Don't know? Would it surprise the panel to learn that they classify their distribution mains 100% to demand?

A. I don't know.

Q. Okay. Can we move to page 29 of your rebuttal testimony? At line -- beginning at line 17 you make reference to the NARUC gas distribution rate design manual, is that right?

A. (Crahen) Yes.

Q. Okay.

MR. ZIMMERMAN: Your Honor, can we -- can we approach the bench with a copy -- with a document?

A.L.J. LECAKES: Yes. Please do.

BY MR. ZIMMERMAN: (Cont'g.)

Q. Panel, can you identify this document?

A. The title of the document reads gas distribution rate design manual prepared by the NARUC staff subcommittee on gas June of 1989.

Q. Is this the same NARUC manual that you

reference on page 29, line 17 of your testimony?

A. Subject to check, it's a pretty voluminous document, so it -- it would be hard to go through the whole thing here right now.

Q. Understood. But upon initial review that appears to be the -- the NARUC manual?

A. Yes.

MR. ZIMMERMAN: Your Honor, can we have this document marked for identification in the record?

A.L.J. LECAKES: Any objections? I have the next Exhibit number as 253. Marked as Exhibit 253.

UNIDENTIFIED SPEAKER: Do you have copies for the parties?

MR. ZIMMERMAN: Yeah, sorry. We have additional copies for parties.

BY MR. ZIMMERMAN: (Cont'g.)

Q. Panel, could you please turn to page 22 of the NARUC manual and refer to the bottom -- the paragraph at the beginning at the bottom of the page? Starting with the words under the minimum size main theory. Could you please read that sentence that starts with those words?

A. Sure. Under the minimum size main theory all distribution mains are priced out at the historic unit cost of the smallest main installed in the system and assigned as customer costs.

Q. Thank you.

MR. ZIMMERMAN: Your Honor, I'd like to introduce as an additional exhibit, or excuse me, this was on the group exhibit list of IRs, but I'm not sure it has a -- a -- a number for identification yet.

A.L.J. LECAKES: That's right. I'm sorry, we didn't -- we didn't introduce it earlier. I had intended to do that. I -- I don't -- since it's being stipulated to by all parties I think we can introduce it now and -- and mark it as an exhibit. So we'll mark it as Exhibit 254 and that way we can refer to it that way on the record, so you can just -- Exhibit 254 and then the individual IR number.

MR. ZIMMERMAN: Thank you.

BY MR. ZIMMERMAN: (Cont'g.)

Q. So in -- in that exhibit I'd like to refer to the company's response to UIU information request number 67. And we have -- we have copies if you like.

Now company's response to Letter A reads in part, quote, the company utilized minimum size,

in parens, 2-inch cuts per foot to -- to confirm the reasonability of the 0 intercept method. Attachment A to this data request response provides a copy of the minimum size analysis, is that correct?

A. (Meinl) Yes.

Q. Okay. So turning to attachment A what is the smallest main in the company's system?

A. (Crahen) Smallest size is 0.999 in referring to Attachment A.

Q. Uh-huh. Does that size pipe connect any customers to the distribution system?

A. (Meinl) That specific the 3,212 feet out of 50,379,672 feet?

Q. I'm not asking about each -- each specific foot of -- of main. I guess my question is does that main serve customers? Does that pipe serve customers as used in the company's system?

A. Can you define serve customers?

Q. Does gas run through it?

A. Don't know where this pipe is located. I don't know if it's off a gathering system that does not serve many customers or move much or any gas, so I really can't speak to the amount of gas that flows through the 3,212 feet out of 50,379,672 feet.

Q. Certainly not asking about the volume about -- that goes through that pipe in particular. I guess my question in general is that pipe serves a purpose in the company's system, is that fair to say?

A. I would assume it does, yes.

Q. So presumably that -- that main serves the demand of those customers who are attached to it?

A. I don't know if there is any customers attached to it.

Q. But if there were?

A. If there were --.

MR. DELVECCHIO: Calls for speculation, your Honor.

A.L.J. LECAKES: I'll let the question and answer stand, but I -- I do note the company's concern with it.

MR. ZIMMERMAN: Okay. I'll move on.

BY MR. ZIMMERMAN: (Cont'g.)

Q. So how many different sizes of pipe does the company have in its system as indicated by Attachment A?

A. I'm sorry, could you repeat the question.

Q. How many different sizes of pipe are

there in the company's system? I -- I don't mean to make you count up everything right now.

A. No, no. I'm -- I was just I was doing the quick math on the rows. It looks like there are 32.

Q. Yeah. Although I -- I note that size 5.250 appears to have 0 feet, so maybe we could call it 31.

A. Maybe we could.

Q. So of those 31 how many have a lower average per foot embedded cost than the 2-inch main?

A. 18.

Q. 18. I have 19 but I -- you know, 18 sounds good too. So but the majority are cheaper than -- than the 2-inch main in terms of average embedded per foot cost?

A. (Meinl) Not under current -- current pricing. I mean you're looking at -- you're looking at legacy pipe that may not have been installed since 1950. The -- if -- if you speak with our engineers, we predominantly and almost exclusively now install 2-inch main as the minimum size main.

Q. Understood. But in terms of embedded?

A. And that's -- that's why we've got like a 19,243,579 feet of it which is close to -- if I do

my math in my head quickly enough I come up about 40% of our -- our total footage.

Q. But in terms of embedded -- in terms of embedded pipe.

A. (Crahen) Can you define embedded pipe?

Q. By presently installed in the company's system. Okay.

A. Yes.

Q. Okay. So I'd like to go to Exhibit COSRD 23 which is a map, the company's service territory. Now we've -- we've actually -- we've taken the liberty of printing up a -- a larger copy of it for the -- the panel to look at, and we also have some smaller copies. But it's -- there's a -- a number of dots close together so we wanted to blow it up for you.

A. Yeah, this isn't by the way the entire service territory. It's one section of our -- our --.

Q. Understood. My apologies if I misspoke. Can the -- can the panel identify what -- what this map is showing?

A. Yes. Schedule 1 and Schedule 2 of Exhibit 23 represents 2 snapshots of the company's distribution system from our GIS system.

Q. Okay. So taking a look at Schedule 1

I see yellow lines that indicate mains and then green dots that indicate residential customers, blue dots for commercial and orange dots for industrial customers, is that correct?

A. Yes. That's correct.

Q. So I'd like to draw the panel's attention to Schedule 1 page 1, Casey Road (phonetic spelling) which runs along the southern edge of that particular snapshot. Let me know when -- can you see that?

A. Yes. I got it

Q. And for the eastern portion of Casey Road it appears that there's a single 3-inch main running along that road, the majority of it, is that right?

A. Yes, that's correct. Near Casey near Route 78 Transit Road right near that corner, that part of the system near Transit Road is 3-inch pipe.

Q. Okay. So I'd like to ask about the -- these 3 neighborhoods that lie just to the north of Casey Road and the -- the -- if it's all right with you I'd like to just refer to them by the -- by the name of the street that connects them to Casey Road. So from west to east we've got Twilight, Bramblewood (phonetic spelling) and -- and Breezewood, is that -- is that okay?

A. Okay. Yeah, that's correct.

Q. So each one of these neighborhoods appears to have several customers in them, is that right?

A. Yes, that's correct.

(Meinl) Several residential customers.

Q. Several residential customers.

A. (Crahen) Yes.

Q. Yes. So subject to check and it -- it took me a while to count these out, but subject to check would the panel agree that there are approximately 77 customers in the Twilight Lane neighborhood?

A. Subject to check.

Q. Subject to check.

A. (Meinl) Yes.

Q. And, again, subject to check 95 customers in the Bramblewood neighborhood?

A. (Crahen) Again, yes, subject to check.

Q. And finally 82 in the Breezewood neighborhood?

A. Same response. Subject to check.

Q. Now each of those neighborhoods appears to be served, or excuse me, connected to the Casey Road 3-inch main by a single length of 2-inch main. At least taking a look at the Twilight Lane neighborhood

there appears to be just a single length of 2-inch main connecting that neighborhood to Casey Road, is that right?

A. (Panel) Yes.

Q. Okay. And for Bramblewood again, a single section of 2-inch main?

A. (Crahen) Yes.

Q. And Breezewood 1 section of 2-inch main?

A. Yes.

Q. Okay. So then in the case of the Bramblewood Lane neighborhood that single section of 2-inch main is able to carry the gas to all 95 customers in that neighborhood, is that right?

A. (Panel) Yes.

Q. Okay. So at least in the -- in the company's service territory a 2-inch main can, subject to check -- subject to checking the numbers, a 2-inch main can serve the demands of 95 customers?

A. (Crahen) Well, it's -- it's not a yes or no answer. 2-inch main is the standard pipe size that gets installed in the company's distribution system. Our -- our chief engineer who spoke yesterday can elaborate more on this. That 2-inch pipe size is -- it being the standard size that gets installed in the distribution

system, it's not at all based on the load of, you know, 70, 80, 90 customers. It's just standard size pipe that pipes neighborhoods that are entirely -- and in this case entirely residential customers.

All those mains in those 3 neighborhoods and all the footage for those mains running up and down roads, Bramblewood, Twilight, Breezewood, all those footages of pipe really do belong to the residential customer class. There's not a single commercial or industrial customer in any of these neighborhoods.

Q. I -- I agree with that statement -- that last statement that you made about the commercial and industrial customers. But I guess the question is at least with respect to -- subject to checking the 95 customer number, right, that 2-inch main can serve 95 customers worth of demand?

A. In this case as part of the system this 2-inch main is serving those customers. Again, with that being a standard pipe size it's not at all based on the demand of those customers. It's the standard size pipe to connect those customers to the company's distribution system.

Q. Understood. Now I understand that this is -- this is not something that I would ask the

panel to -- to do with precision on the fly, but subject to checking the number of customers in the neighborhood, and again, 95 in Bramblewood approximately and 82 in the Breezewood neighborhood approximately, assuming those numbers are correct that would mean that the Bramblewood neighborhood would have 14% more customers than Breezewood give or take?

A. (Meinl) Subject to check, yes.

Q. Okay. Now in terms of main installed in those neighborhoods which neighborhood has more footage of main installed?

A. It appears it's the Bramblewood.

Q. Uh-huh. Can the panel estimate how much more footage --

A. No.

Q. -- in Bramblewood? Okay.

A. (Crahen) No.

Q. Subject to check could the panel agree that there could be 3 times more footage of main installed in that neighborhood?

A. (Meinl) I'm not -- not -- I'm not going to agree to a 3 time number subject to check.

(Crahen) Yeah, based on the map, I mean, it -- visually it -- they appear to be similar to

each other, those 3 neighborhoods.

Q. So if we -- if I took out a ruler and we measured the mains.

A. Subject to check the company could go into the GIS system and get exact measurements for each of these pipe type.

Q. Uh-huh.

A. And we don't have the GIS system here with us today.

Q. Okay. Can we go back to Attachment A please on the company's response to UIU 67?

So the company's 0 intercept analysis indicated a 0 intercept result of $8.27 per foot of main, is that right?

A. (Meinl) Yes.

Q. Okay. Of the 31 sizes of pipe embedded in the company's system that's shown in Attachment A how many have lower average per foot embedded costs than $8.27?

A. (Crahen) 17 when you exclude the -- the 5.2 -- excuse me, the 5.250 size with 0 that we discussed earlier today.

Q. Okay. Thanks. So I'd like to turn very briefly back to the NARUC manual, page 22. The last

full paragraph on that page beginning with the words a portion. Can the panel please read the first 2 sentences of that paragraph?

A. Under the minimum size main theory -- oh, the paragraph above?

Q. No. Yeah, the paragraph above beginning with a portion.

A. Sorry. Excuse me. A -- a portion of the costs associated with the distribution system may be included as customer costs. However, the inclusion of such costs can be controversial.

Q. Thank you.

A. (Meinl) Although -- although I don't think there's -- has been any controversy in our rate case in the last 20 years.

Q. Okay. Does the -- does the NARUC manual discuss other potential methods of allocating gas mains?

A. (Crahen) It may. We looked at the NARUC manual and found that our method was included in that manual.

Q. Okay.

A. (Meinl) 0 at minimum. Or minimum size. We took that to read it could be the 0 method or

the minimum size method.

Q. Uh-huh. Can you turn to the next page please, page 23? Top of the page, the first full sentence on that page beginning with the words a calculation. Could the panel please read from that sentence to the end of the paragraph?

A. (Crahen) A calculation of a minimum sized main is shown in the illustrative cost allocation study. The contra argument to the inclusion of certain distribution costs as customer costs is that mains and services are installed to serve demands of the consumers and should be allocated to that function.

Under this basic system theory only those facilities such as meters, regulators and service taps are considered to be customer related as they vary directly with the number of customers on the system.

Q. Thank you. Does the NARUC manual indicate that this basic system theory is incorrect?

A. (Meinl) No, it states it’s the contra, and since it’s the contra of what’s defined as a controversial method, I would assume the contra method is also controversial.

Q. Does the NARUC manual actually identify this contra method as controversial?

A. I -- I'm reading contra is the similar but opposite of -- of the other method. And since the one is controversial I would assume the contra is also controversial.

(Crahen) Yeah, and earlier in this section on page 22 the second full paragraph under customer costs it does cite the inclusion of such costs can be controversial. So to Eric's point that -- that could be 1 method or the other since both are being discussed here in Part A, the customer -- customer costs section.

(Meinl) And -- and, again, the controversy was resolved 20 years ago. Out of the grave in this case comes this issue again. It was resolved 20 years ago. We filed I think 2 rate cases since and it wasn't an issue. And if you look at the maps and -- and, you know, you stopped at the -- at the residential cul-de-sacs and you ignored the feeder systems that feed into Casey Road and then feed into the residential cul-de-sacs, and you'll notice that's where our commercial customers are. And if you look on the map on Schedule 1, most of those mains served exclusively residential customers.

You go to Schedule 2, those also exclusively serve residential customers for the most part.

The demand method that -- that is talked about on the pages you just referenced, that demand method says take all the mains including these that exclusively serve residential customers and allocate them solely on the coincident demands of all the classes of customers. And effectively allocating to industrial customers and the commercial customers, all those mains that's sort of exclusively residential customers.

Q. I'd like to clarify one thing that you just said. So it's the panel's opinion that the -- that allocating mains 100% on demand effectively allocates all the costs of mains that are serving residential customers to industrial and commercial customers?

A. It -- it pools mains, all main sizes as one cost. So all these residential -- exclusively residential mains get thrown in the pool of dollars. And then it says what's the coincident peak demand of each class of customer effectively allocating based on -- on the factors that we've included in our cost of service study for peak demand effectively allocating a proportion of these mains that exclusively serve residential customers to the industrial and commercial class of customers that we've demonstrated on these maps are served off of feeder mains not off of mains that extend into

residential neighborhoods.

Q. Does the company system have any mains that exclusively serve industrial or commercial customers?

A. Yes -- yes, there is an example. It's in the cost of service study. A portion of the cogeneration customer that we've included in -- in that study, there's mains that serve that customer. And we carved out those costs and assigned it exclusively to that -- that class of customer.

Q. Are there any -- any other places in the company's service territory where it might have a main that only serves an industrial customer or a commercial customer?

A. I -- I don't know.

Q. You're not sure?

A. Yeah, I -- I don't know. It very well could be.

Q. Okay. Can we move -- sorry. Can we move to the panel's rebuttal testimony of page 26? So beginning at line 9 looks like the panel has a quote or quotes UIU, is that correct?

A. (Crahen) Yes, that's correct. Line 9 on that page we have a quotation from UIU.

Q. Okay. And that quoted portion cites

to UIU's direct testimony of page 16, quote, customers who value the product most or purchase the most quantity typically pay a larger share of joint cost than customers who buy less or value the product less, is that right?

A. That's what the quote reads, yes.

Q. Is that a complete quote of the sentence in the UIU rate panel's direct testimony?

A. So in referring to the UIU rate panel's direct testimony beginning at line 17 it reads customers who value the product the most or purchased the largest quantity typically pay a larger share of joint costs than customers who buy less or value the product less.

Q. That -- that sentence begins in competitive markets, right?

A. Yes, it does.

Q. Okay. So the quoted portion in the panel's rebuttal testimony wasn't a complete quote of the sentence, correct?

A. (Meinl) That -- that's correct. That's why we started the -- the word customer with a lower case in quotes.

Q. Uh-huh. So taking a look at the -- the complete sentence in the UIU -- excuse me, in the UIU

direct testimony, page 16, line 17, does -- does the company agree, or excuse me, does the panel agree with that statement in competitive markets those customers who value the product most purchase the largest quantity typically pay a larger share of joint costs than customers who buy less or value the product less?

A. I think that's an overbroad statement.

Q. Okay. Can you explain why?

A. I -- I believe there are many competitive companies that are -- their business model is based on volume so they'll buy a -- a large amount of a product at a -- at a relatively low cost. So without -- you know, exploring all the different industries that make up a competitive market, again, I think that's -- that's just overbroad.

Q. So in your rebuttal testimony, page 26, line 16 reads, quote, yes, Exhibit COSRD 22 confirms this fact. Can you identify the fact that's confirmed?

A. That -- that customers -- the -- it's the question on line 13 --

Q. Uh-huh.

A. -- will customers that buy more gas on the company's system be charged more for delivery service than those that use less? That's the fact.

Q. Okay. Uh-huh. So customers on that company's delivery system who use more gas tend to be charged more than those who are -- that -- than those who use less, correct?

A. Yes.

Q. Okay. Can I ask -- so on page 26, line 16 the panel's rebuttal testimony --.

A. (Crahen) I'm sorry, what page was that?

Q. I'm sorry, page 26.

A. Thank you.

Q. Beginning at the end of that line reads, quote, what UIU is actually saying is that customers that use more gas should pay an even greater share of the system's fixed costs than they pay today. Can you identify where in UIU's direct testimony it actually says that?

A. (Meinl) That's the consequence of reducing minimum charges and increasing -- increasing volumetric rates. It just -- it's like night follows day. That's how the math works. You can't get around it.

Q. Can I -- let's turn to page 28 please. Excuse me, page 27 beginning at line 14. Can you describe the calculations that are described in this paragraph?

A. (Crahen) Yeah, on page 27 at line 11 panel describes the calculation that was performed. We took a look at customer usage for the historic test year as well as the number of bills issued by service calculation and used that as just a representative sample of mathematics that then follow in that section of the testimony.

Q. Sorry, which section of the testimony?

A. So I'm referring to line 11 on page 27. And so the first couple lines there, line 11, 12, 13 and 14 it kind of outlines what we have done, you know. We've taken the historic test year usage and we've also looked at the number of bills by service classification. And then the mathematics that follow that logic that starts up with the sentence that reads using these on line 14 and then continues through the rest of the page.

Q. So that's -- so the -- the company performed that -- that calculation?

A. Yes, the company performed that calculation and --.

(Meinl) Comes off of our revenue exhibits.

Q. Uh-huh. So -- so it indicates that during the historic test year service classification 2 B

LICAP customers used 33.9% more gas than service classification 1 customers? Is that correct?

A. (Crahen) Yes, that's correct.

Q. Okay.

A. Service classification 2 B that represents low-income payment trouble customers that tends to use the most amount of gas compared to normal residential customers, SC One.

Q. And then on -- beginning on line 20 it reads, quote, UIU is essentially recommending that LICAP customers should pay 33.9% -- and I'll skip the parens -- more than the average residential customer for delivery service simply on the basis that these customers use more gas. Is that correct?

A. Yes, that's correct.

Q. Where did UIU state in this direct testimony that there should be a 1 to 1 relationship between the amount of gas a customer uses and the amount that that customer has to pay?

A. So getting back to page 26 starting at line 9 the quotation that we were discussing earlier, UIU stated customers who value the product most or purchased the largest quantity typically pay a larger share of joint costs than customer -- or joint costs, excuse me, than

customers who buy less or value the product less.

And so in this instance for a low-income payment troubled customer that's using 33 or 34% more gas that customer should pay a larger share of those costs than the SC 1 customer who's using significantly less gas if that quotation is taken literally.

Q. Does that quotation indicate a 1 to 1 relationship between the amount of gas used and the amount paid for that gas?

A. The quotation reads, customers who value the product most or purchase the largest quantity typically pay a larger share of the joint costs than customers who buy less or value the product less. That's -- that's what it reads.

Q. But does it indicate a 1 to 1 relationship?

A. That quote does not have any statement about a 1 for 1 relationship.

Q. Okay. So that was the company's addition?

A. (Meinl) It's our interpretation of -- of that statement.

Q. Okay. Did you UIU indicate in this quote on page 26, line 9 that the amount a customer pays

for gas should disregard other factors about that customer? For example, their low-income status?

A. That sentence? No, it did not say that.

Q. Did -- did UIU say it anywhere in their testimony?

A. (Crahen) Have to go check. I'd have to read through it again.

Q. Okay. I mean, I ask because the panel is imputed to UIU this particular calculation.

A. (Meinl) I understand.

(Crahen) Yeah, what the panel was trying to show here is just a simple illustrative example of what happens when a customer uses more than other customers.

Q. Uh-huh.

A. So in this case for a low-income customer using more gas, just -- just the basic notion is that they should be charged more money than somebody who uses less gas. I guess another good example of that might come later in the -- in the -- the panel's testimony where we talk about seasonal homes.

So using that same hypothetical construct, you know, a low-income customer might use

double the amount of gas as a seasonal home. A home that's only connected to the distribution system maybe 3, 4 months of the year. So in that case if that statement, that quotation is taken literally, you know, that seasonal home might pay significantly less than a low-income payment troubled customer with high usage that's residing in poor housing.

(Meinl) And I guess I'd also add UIU's testimony throughout their testimony or at least -- not throughout -- at a portion of their testimony talked about competitive markets and how -- how their costs are recovered through volumetric rates and -- and usage of a product implying that it be connecting to a gas system isn't usage. But basically you go to a -- a competitive market and you buy a product, you pay for what you use.

So it's not -- I don't think it's unfair for us to -- to imply that UIU was recommending or at least trying to recognize that most if not all costs should be recovered through usage rates. If you -- if you draw analogy to competitive markets and say that their -- their products -- purchase other products are recovered through -- through usage, we just naturally took the implications of that statement.

Q. So it's the panel's opinion that that

-- that quoted sentence on page 16 of the UIU's testimony is a prescription for how precisely NFG's cost should be recovered?

A. No. No. No.

Q. Okay. It was an example.

A. (Crahen) Yes.

(Meinl) And, again, it -- it -- it was reading your -- your competitive analogies in -- in taking them and applying those theories to our system. And I wouldn't agree with you that UIU is not recommending that 100% of the cost be recovered through volumetric rates.

Q. Okay. Let's go then to page 31 please. Beginning at line 13 the panel quotes UIU's direct testimony at line 40. That quote reads, quote, a single service can be shared by multiple customers of varying sizes. For example, the same service may deliver gas to retail stores and offices of widely varying sizes located in the same building.

Similarly, the same service may be used by apartments of widely varying sizes placing different demands on the service. Is it -- does the panel agree that a single service can be shared by multiple customers of varying sizes?

A. Yes.

Q. Does the panel agree that the same service may deliver gas to retail stores and offices of widely varying sizes located in the same building?

A. (Crahen) Yes, but that phenomenon tends to be more of the rarity in distribution system. For example, if you look at the map that we were, you know, looking at earlier, the GIS map, so that's Exhibit 23 Schedule 1. So here you have a case -- let's look at Route 78.

Q. Well, I -- I think -- I don't want to get too far afield. I mean, I'm -- I want to ask about -- I mean, that map doesn't show services.

A. Well, it shows main lines and main line -- in order to connect all these customers here that you see on the map to those main lines there needs to be a service line. There's no other way to hook them up.

Q. Uh-huh.

A. This is the exact example, the exact representation in the company's service territory. Most of these -- most of these homes here are residential. There -- there's neighborhoods just like this. You pick a zip code in the company's service territory, all throughout the western New York service territory unique to distribution systems are neighborhoods like this.

What you have in -- in Manhattan or downtown New York City the phenomenon where there might be a deli and a bodega there on -- on the first floor and second floor and then housing units above it, that is not readily prevalent in the company's service territory. Most of the neighborhoods tend to be residential.

So although it is possible that there might be some services in the system that -- that could serve mixed-use customers that tends to be the extreme rarity in the company's service territory.

Q. Yeah.

A. It's unique to us compared to other utilities in New York State.

Q. Yeah, so actually I -- I want to ask you about that. You -- you're making reference to a service that shares a mixed use customer, retail and commercial, for example?

A. As a hypothetical.

Q. As a hypothetical?

A. Yeah.

Q. Does UIU's testimony address services shared by mixed use customers or customers of mixed uses?

A. So the -- the quotation that we just looked at, if you refer to the rebuttal testimony of the

cost of service and rate design panel, if you look at -- at line 13 there we included a quote from UIU's testimony at page 40. A single service can be shared by multiple customers of varying sizes. So it -- it appears that, yes that is included in UIU's testimony.

Q. Of varying sizes. Customers of varying sizes.

A. And then, well, for example, the next sentence in that quotation it says, for example, the same service may deliver gas to retail stores and offices located in the same building. Similarly, the same service may be used by apartments of widely varying sizes. So in this exact quote we're referencing retail stores, offices and apartments all being fed off of the same service line. So that's very much part of UIU's testimony.

Q. I think I understand. I'm glad we can clarify this. That latter part of that quote line 17 to 19, the same service may be used by apartments of widely varying sizes placing different demands on the service. Does the panel agree that that's true?

A. (Meinl) Is it a possibility?

Q. Uh-huh.

A. It -- it's a possibility depending on the square footage of -- of the various apartments and --

and the design of the apartment building.

Q. Okay. So I only have one thing I'd like to ask about additional. So the panel made reference earlier to the 1995 case.

A. (Panel) Yes.

Q. Yes. Case 94-G-0885, right?

A. (Crahen) Yes, that's correct.

Q. Okay. So turning to page 25 of your rebuttal testimony -- so the panel makes reference to the recommended decision in that case and the order in that case, right?

A. Yes, that's correct.

Q. The panel make reference to any of the parties' testimony or briefs filed in that case?

A. The panel referred to the order in the recommended decision that was cited in the company's testimony. In -- in reference to those materials there were sections the panel included in its testimony where the positions of other parties were being characterized and presented in those 2 documents. The -- the commission's order as well as the A.L.J.'s recommended decision.

Q. Right. But the documents themselves aren't cited to in the testimony?

A. (Meinl) We presume the A.L.J. got -- got the quotes out of the -- their documents.

Q. Yeah. Is the panel aware that the testimonies and briefs in the hearing transcript for that case aren't available on DMM?

A. I am vaguely aware based on the judge's e-mail sending all the parties the A.L.J.'s RD.

Q. Uh-huh. Did the -- was the panel aware that the company's briefs aren't available in the state archives from that case?

A. I don't know the answer.

(Crahen) We -- yeah, state archives.

(Meinl) Policies.

Q. Did --.

A. I think -- I think though CPB which I believe was your predecessor agency was a party to the case, received all the documents, wrote their briefs and I presume has their own filing system.

Q. So, I mean, since you bring it up, were -- are CPB and UIU the same agency?

A. I -- I don't know.

Q. Okay.

A. But it's my understanding that -- that the UIU evolved from the CPB.

Q. Okay.

A. (Crahen) And it should be noted too that, you know, the company readily and very quickly and on short notice did provide those materials that were referenced to all the parties instantaneously in this proceeding.

Q. The recommended decision in the order.

A. The order -- the order and the recommended decision.

Q. Did the company provide the company's own briefs from that case?

A. We're referring to a case from 1994. At that time I was 7, 8 years old. We have them. They're -- they're in boxes somewhere in storage I -- I believe. We'd have to go look.

Q. Okay.

A. I mean, just based on pure record retention guidelines, you know, we would be -- we would have to go hunting and pecking for a document that's 20 plus years old at this point in time.

Q. Uh-huh. Right.

A. But we do believe as we stated in our testimony though, even though that might be the case, we do believe that the documents that we referred to and the

documents that we referenced here in our testimony and provided to all the parties, we do believe that that's an accurate representation of the case. We believe the A.L.J. characterized the case the right way, and we agree with the commission's decision in that case. We believe that, you know, that that's a true representation of the parties.

Q. Okay. I mean, but is it possible that facts have changed between 1994 and now in the company service territory?

A. (Meinl) Facts -- facts change but if you look at the -- at the part of the Exhibit 5 I believe there were -- the age of homes that were -- were built. And if you look at the 1 zip code that we included, the 14215 zip code that has that extensive amount of residential mains, I believe that area of the city was built in the early 1900s, 1910, 1920. So the -- the facts about mains being installed to serve residential customers, I don't think that has changed much if at all.

(Crahen) And -- and also probably the facts about the neighborhoods being prevalent throughout the company's service -- service territory. That -- that's something that has remained the same.

Q. Okay.

A. Since this ’95 case to now.

Q. Well, it could be tough to know for sure without the actual facts of the case, right?

A. (Meinl) I -- I think you can know for sure. It’s not like this is Paris or Buffalo is Paris of 1865 where they -- they did a complete urban renewal and ripped down every -- every house and -- and rebuilt boulevards. That’s pretty plain to see.

(Crahen) Yeah. And we’ve lived there for 75 years. It’s pretty much the same when it comes to the neighborhood construct, the developments, the old housing stock. There’s key facts that just don’t change over time. They’re timeless.

Q. Did UIU ask for any documents besides the RD and the order from the company with respect to that ’95 case?

A. (Meinl) I believe we did, yes.

(Crahen) I believe, yes.

Q. Yeah. Did the company provide them?

A. (Meinl) I do not believe we did. We referenced the fact that it was our understanding that you had those documents.

Q. Okay.

A. We were also directed to many various

information sources by -- by the parties.

(Crahen) Yeah, I think UIUs and some of the other parties' testimony refer to a number of proceedings outside of New York State on a national level. We -- the company didn't receive orders, briefs. We didn't receive work papers, analyses that were completed for any of those cases. Setting aside the whole issue that those cases might not apply directly to the company's service territory, we didn't receive any of those materials in -- in this proceeding.

Q. Okay. All right. Thank you, panel. I'm all set.

A.L.J. LECAKES: Before I turn to the next cross examination I just want to note that for the record the company did provide that recommended decision pursuant to my own request after reading the cost of service rate design panel rebuttal testimony when I was unable to find a copy of the recommended decision.

I did not request any other documents in -- in that case. I am unaware of any discovery that was forwarded in this case from the parties on those underlying documents, because no discovery dispute was ever brought to my attention about that.

But, Mr. Mager?

CROSS EXAMINATION

BY MR. MAGER:

Q. Thank you. Good morning, panel.

A. Good morning.

Q. Panel, I'd like to start by following up a -- a couple of lines or questions asked by UIU's counsel. Can you please turn to your response to UIU's 67 which is part of the larger Exhibit 254?

A. 67, Mike?

Q. Yes.

A. Oh, yes. Okay. Got it.

Q. The one that you had just -- and if you go to attachment -- the attachment to that IR response I see that the 2-inch size has underlined above and below it. Can you just explain why that was highlighted in that way?

A. Yeah, the -- earlier today we were discussing 2-inch pipe in the context of -- of the GIS maps. 2-inch pipe is significant because that's the pipe size that the company typically installs in its distribution system when it's performing pipeline replacement work.

Q. And that's the size used in your -- your zero intercept analyses?

A. (Meinl) The -- the -- among the -- it's among the sizes used, yes.

Q. And when you state -- state on the interrogatory response, the third paragraph that the company utilized minimum sized 2-inch cost per foot to confirm the reasonability of the zero intercept method, can you explain why that size was chosen?

A. (Crahen) So 2-inch is the standard pipe size that's installed on the company's distribution system. The reason we had chose that earlier we were discussing the NARUC manual there was that quote in there. On page 22 they refer to a zero or minimum size theory. And so the company's method is the zero intercept method. The reason we included the 2-inch was to demonstrate the reasonability of the company's method when compared to the, quote unquote, minimum system method that was being referred to in that -- in that NARUC manual.

Q. Thank you. And if you go back to the attachment I -- I believe Mr. Meinl mentioned that the company has approximately 50.4 million feet of pipe, is that correct?

A. Yes.

Q. And counsel for UIU asked about the number of sizes. I -- I guess I'd like to ask a variation

of that. How many size pipes does the company have more than 1,000,000 feet for?

A. Yeah. Just bear with me. It appears that it's 10 in referring to that attachment.

Q. Yes. And am I correct that out of those 10 the 2-inch pipe actually has the lowest cost per foot?

A. Again, bear with me here.

Q. No, I'm -- I'm sorry. It's not.

A. It's not.

Q. It's -- there's one that's 4 cents less, correct?

A. The -- the 4-inch pipe has an average cost per foot of 11.47. The 2-inch has one of 11.51 that are very, very close to one another. Aside from that, Mike, it appears just based on a very quick review here that all of the other pipe sizes do exceed the average cost per foot of -- of the 2-inch.

Q. And do you recall answering questions on the -- the smaller size pipe, the 0.9991?

A. Yes, we do.

Q. Now of the -- of the pipe sizes smaller than 2 inches, am I correct that only 1 other pipe size has more than 1,000,000 feet on the company's system?

A. Yes, that's correct. Out of the -- it appears to be 7 pipe sizes that are less than 2 inch. Only the 1.225. So, yes.

Q. And that one has a higher cost than the 2-inch pipe?

A. Yes, that's correct. That 1.25 has a average cost per foot of 14.41 compared to the 2-inch pipe with an average cost per foot of 11.51.

Q. Thank you. Can I direct your attention to what's I believe is your Exhibit 23, the maps, the 2-page maps? And, in particular, let's just look at the first page. I believe that's the one that's blown up as well.

A. Okay.

Q. Everyone have it? Okay. Now do you recall being asked a number of questions about 3 developments off of Casey Road? They were all residential developments?

A. Yes.

Q. Now am I correct that if -- let's just take 1 example, the Bramblewood development, if there was only one or 2 houses on Bramblewood Lane right off of Casey Road, the -- the number of pipe necessary to be installed would have been a lot less, correct?

A. It depends where in that neighborhood it's located. But, yes, you -- you probably wouldn't need the full footage that's shown here for that neighborhood.

(Meinl) If you -- assuming you're defining right off Casey Road to be not many streets over, yes.

(Crahen) Yeah.

Q. And if there were -- and then if there were 5 or 6 houses that got built next to that, you would then have to install the -- install additional main to serve them, right?

A. (Panel) Yes.

Q. And so -- and in that case there would still be significantly less main installed than what we have now with these developments, correct?

A. (Crahen) In that example, yes.

Q. Right. So in this case the fact that the -- that more houses were developed and that led to the installation of more mains being installed, correct?

A. Yes.

Q. Thank you. Can we just follow up quickly on the NARUC manual that has been marked Exhibit 253? I believe counsel for UIU asked a -- a series of questions I believe referring primarily to page 22, the

section dealing with customer costs. Do you recall those questions?

A. Yes, we do.

Q. Okay. Now I'd like you to -- I'd like you to look at pages 23 and 24. At the bottom of 23 there's a section on demand or capacity cost, do you see that?

A. That Section C there? Yes.

Q. Yes.

A. Yes.

Q. Okay. And can you please -- can you please read the sentence starting on page 24 that starts included in -- in terms of what's included in demand or capacity costs?

A. Yes. That first full sentence, Mike?

Q. Yes.

A. Included in these costs are the capital costs associated with production, transmission and storage plant and their related expenses. The demand cost of gas and most of the capital costs and expenses associated with that part of distribution plant not allocated to customer costs such as the costs associated with distribution mains in excess of the minimum size.

Q. Okay. So that's saying that in terms

of the distribution plant that is assigned to demand or capacity it's the part in excess of the minimum size, is that correct?

A. Yes.

Q. And that's essentially the -- the approach followed by the company if you assume minimum size and the same general methodologies?

A. Yes.

Q. Thank you. Let's -- let's go back a little bit and -- and have some questions for you on your direct testimony. If you -- whenever you get a chance if you could turn to page 3 please.

A. Okay. We're all set. Thank you.

Q. Okay. Now you state on --.

A. (Meinl) Hold on, hold on a minute, Mike. Sorry, we got the wrong page.

Q. Take your time. Could you read the first sentence on page 3?

A. (Crahen) First sentence on page 3 states the embedded cost of service study presented in this proceeding is voluminous and relies on the number of special studies and related work papers.

Q. Okay. And who -- who prepared -- who's involved in the preparation of the cost of service

study?

A. (Meinl) Both Mr. Crahen and myself.

Q. Okay. And approximately how long did the study take to prepare?

A. (Crahen) Start to finish, different pieces of the study spanned roughly 4 months leading -- 4 or 5 months. And then further analysis continued as part of the rebuttal phase.

(Meinl) Once we started planning for a rate case we ran various reports and -- and obviously as we got the revenue requirement, the amount of time spent on the study expanded.

Q. So it's fair to say it was a substantial undertaking?

A. (Crahen) Yes, that's correct.

Q. And you performed a number of what you call special studies. Can you just identify some of those please?

A. Sure. So if you -- if you refer to page 7 of the direct testimony of the panel we -- we've laid out for convenience a number of work papers that were entered into the record today. Different -- that first column provides different names of studies and items that the company looked at and assessed. And then the right

hand column refers to the names that the company is referring to these items as as part of the record.

Q. Okay. And if you -- it's a general question but I guess it's starting to touch on testimony on page 8, would you agree that one of the primary purposes of a cost of service study is to determine the relative cost to serve each customer class?

A. Yes.

Q. And would you also agree that the results of a cost of service study is at least one factor typically considered in allocating revenue responsibility to the various classes?

A. Yes. Although the company did present an exhibit outlining a number of other factors. But, yes, the cost of service study is one of several factors considered by the company.

Q. Would you agree it's an important consideration?

A. It's one of many considerations.

Q. Okay. Now starting on page 20 you discuss the classification factors assigned to various expenses. Do you see that?

A. Page 20? Yes.

Q. And so -- and yet the company's often

allocates costs among different classifications. I think one example you gave is general plant office equipment. Do you see that?

A. Yes, on line 9.

Q. Where for certain office equipment you -- you classified over 26% to demand, correct?

A. Yes, so that category of office equipment furniture was classified 26% demand and roughly 74% to the customer.

Q. And that -- that was irrespective of whether the furniture was assigned to the distribution function or the supply function, right?

A. Yes, that --.

Q. I believe that's what you said.

A. Yes. That's correct. We did state that on lines 11 and 12.

Q. So and -- and -- in terms of general plant office equipment furniture that account, like is a desk something that would be an example of a cost under that account?

A. Yes.

Q. So in this example you could have a desk that's used in the supply function by someone who buys gas supplies. And basically what you're saying is

that the cost of that desk is going to be classified 26% or so based on the customer's demand even transportation customers who don't buy gas from the company. Is that -- is that fair?

A. Could you repeat the question?

Q. Sure. So this desk that's used by someone who just buys gas supplies, am I correct that for that -- for that desk portion of the costs are assigned to transportation customers who don't buy gas from the company and it's based on the -- the customer's demand even though that seemingly has little to do with the cost of the desk?

A. (Meinl) For our -- our 10 person gas supply administration department that also releases capacity to marketers and transportation customers? I think -- I think they -- they perform services for transportation customers as well as for -- for sales customers.

Q. Okay. So you'd say it's partially a matter of judgment in -- in terms of how you -- well, actually how did you calculate that because you got some pretty specific numbers, if you recall?

A. Mike, I'd have to look back at --

Q. Okay.

A. -- into the -- into the depths of the work papers.

Q. Okay.

A. And the -- and the Excel spreadsheet.

Q. Okay. But then going down the page you talk about the assignments made for distribution mains that was the result of a specific study focused on that expense, correct?

A. (Crahen) Yes, that's correct.

Q. Okay.

A. Performed the main study.

Q. Yes. Okay. Let's -- let's jump ahead then. Let's talk about the outputs of a cost of service study. Would it be fair to say that one of the primary outputs of a cost of service study are class rates of return?

A. Yes, that's one of the outputs of the study.

Q. And could you just explain for the record what are -- what are class rates of return?

A. (Meinl) That's the rate of return that results for each service class based on the revenues of each service class and the expenses in plant allocated to each service class. You effectively allocate the net

income of the company into each class of customers and then you divide it by the allocated rate -- rate base to each class of customers to get the rate of return for each class of customers.

Q. Thank you. And could you just also explain for the record what are unitized rates of return?

A. Unitized rates of return is the division of the total rate of return divided into each class's rate of return.

Q. Okay. Can you turn to your Exhibit COSRD 1 which I believe has been marked as Exhibit 201 and I guess in particular could you identify what Schedule 2 is?

A. (Crahen) So Exhibit COSRD 1 Schedule 2 is the company's cost of service study at proposed rates and this is for delivery service only as opposed to Schedule 1 which is a -- a total bundle service.

Q. Okay. So if -- if the commission wanted to know what NFG's position is in terms of the -- the cost of providing delivery service, you would look at Exhibit 201 Schedule 2, is that correct?

A. I'm sorry I'm not following your reference.

Q. Sure. If -- if -- if we wanted to

know what NFG believes is the cost of providing delivery service we -- to the different classes, we would look at Exhibit 201, Schedule 2?

A. Yes.

Q. Okay. Could you please turn to page 14 of 14?

A. Yes.

Q. Let me know when you're there.

A. Yes, we're there.

Q. Okay. Now let's look at the bottom 2 lines, 2 rows for that. One is return earned and that sets off the return for each -- for the company as a whole and then each individual service class, is that correct?

A. Yes, that's correct.

Q. And then below that is the unitized rate of return, correct?

A. Yes. On line 691.

Q. Okay. And so -- and then going across the page it has the different service classifications. Would it be fair to say that the columns TC 1.1, TC 2.0, TC 3.0., TC 4.0 and TC 4.1 all referred to service classification 13, transportation service?

A. Yes.

Q. And the different -- the different

numbers referred to essentially what are subclasses within SC 13 based primarily on the -- the volume of gas consumed by the customers?

A. Yes, each one of those categories has a -- a volume range associated with it, but essentially runs from your smallest SC 3 or 13 customer up to -- to your largest.

Q. Okay. And so am I correct looking at the return earned row that the projected return for the company as a whole is 7.8%?

A. Yes. That's correct.

Q. Okay. And so then if we look at the residential class SC 1 -- SC 1 is residential, correct?

A. Yes, that's correct.

Q. And the return for that class is 5.69%, is that correct?

A. Yes, that's correct.

Q. And so then -- so then when it -- when we look at the unitized rate of return it's compared to the -- compared to the company as a whole it's 0.729 and then some more numbers, is that --

A. Yes.

Q. -- is that correct?

A. Yes. Yes, with more numbers.

Q. So does that -- does that say that the -- basically the SC 1 rate of return is about 27% less than the system average?

A. Yeah, roughly 27% in round numbers, yes.

Q. Okay. Now let's look at the various SC 13 classes. So for TC 1.1 the return you're showing is 24.65% is that correct?

A. Yes, that's correct.

Q. And so that's over 3 times the system average return, correct?

A. Correct.

Q. And then for 2.0 it's -- would -- well, instead of going through all the numbers exactly, is it fair to say that for 2.0, 3.0 and 4.0 you're showing class rates of return that are more than double the system average?

A. Yes and 4.1 as 1.4. But, yes, they're over the system average.

Q. Right. And so 4.1 is -- is approximately 44% above the system average?

A. Roughly, yes.

Q. Okay.

A.L.J. LECAKES: Mr. Mager, about how

long do you expect to go? We -- we've gone a little above an hour and 45 minutes?

MR. MAGER: I -- I would estimate, your Honor, 15 to 20 minutes maybe.

A.L.J. LECAKES: Do you mind if we take a 5 minute break now and then you resume when we come back? All right.

MR. MAGER: Not at all, your Honor.

A.L.J. LECAKES: Let's take a 5 minute break.

(Off the record)

A.L.J. LECAKES: Mr. Mager, please continue.

BY MR. MAGER: (Cont'g.)

Q. Panel, this -- do you stand behind the cost of service study you submitted in this proceeding?

A. (Meinl) Yes.

Q. Do you believe the results of that study establish correctly what service classes are producing above average returns and what classes are producing below average returns?

A. (Panel) Yes.

Q. All right. And just so the record's clear, when we were discussing the various SC 13 service

classes, it -- is the description of the different services classes on page 64 of your direct testimony?

A. (Crahen) Yes, that's correct. They begin right at line 1 and all of the TC classes, Mike, that we've turned and have right there on page 64.

Q. Thank you. Now with respect to SC 13 rate design, I -- I believe it's discussed on page 58, you're -- you're proposing that 100% of the increase to SC 13 be recovered through the volume -- through volumetric block rates, is that correct?

A. (Meinl) Yes.

Q. So none of it would go into the customer charge under your --.

A. Minimum charge, yes.

Q. Minimum charge. Thank you. Did you perform a -- a marginal cost of service study for purposes of this case?

A. (Panel) Yes, we did.

Q. Okay. And what -- what schedule is that just so the record's clear.

A. (Crahen) Just bear with me but we'll find it for you. Mike, it's Exhibit COSRD 1 Schedule 5A.

Q. Thank you.

A. (Meinl) The marginal cost, Mike, you

were asking for?

Q. Yes.

A. C.S. -- COSRD - 4 --

(Crahen) COSRD, yeah, 4.

(Meinl) -- schedule 1.

Q. Thank you. Now jumping ahead, page -- starting on page 71 the company is proposing a system upgrade and modernization tracking system -- tracking -- tracking mechanism, I'm sorry. A system upgrade and modernization tracking mechanism.

A. Yes.

Q. Okay. Now and some of the costs that you would propose be recovered under that would include leak prone pipe replacement costs above targeted amounts --

A. Yes.

Q. -- as well as other costs? And how would this mechanism be applied? Or how would the -- how would the -- the dollars under this mechanism be allocated to the various customer classes?

A. Bear with me for a minute. We had proposed that it would be recovered through the off system sales and capacity release mechanism, the 85% of their ratepayers share. That's in cost of service study rate

design Exhibit 33. We included the tariff.

Q. Is that -- is that still your position in this case?

A. We -- we would -- we were not opposed to staff -- staff's recommendation that it be recovered. I believe that that was over the margin of each -- of each rate class.

Q. So it would be recovered on -- you're acceptable having it recovered if it's approved on a revenue neutral basis based on -- essentially based on delivery revenues and not on a volumetric basis for instance.

A. Yes. We think that that's consistent with the -- the benefits provided to leak prone pipe replacement. We talked about things that -- that didn't change over the last 25 or 20, 25 years. Something that did change over the last 20 years was the -- the competitive position of -- of our various and really all service classifications including our -- our largest service classifications.

And probably the best example of that is 20 years ago when you delivered gas supplies to our service territory you -- you bought gas in the -- in the southwest at -- at NYMEX pricing and you paid about a 10%

premium to move that gas to our -- to our service classification. And we heard back then from -- from large customers that their -- they needed rate discounts and -- and competition was very tough for a number of reasons including competing with other -- other plants and they can buy their gas cheaper in other parts of the country.

That's no longer the case. And we -- we said that in -- in various parts of our testimony. And it's dramatically different. And -- and I'll give you an example.

Q. Let -- let me -- let me ask you about that if I can. In term -- you've testified I believe it's in the -- kind of beginning --.

A. Can I -- can I finish the example though? In October this -- this recent month the cost of gas that -- that we were buying for our sales customers and that we believe our transportation customers can deliver to the system is about 60% less than the NYMEX cost of gas. That's a dramatic -- turns the table right around as far as -- as far as competitive positions.

We had a oil competition 20 years ago. Number 6 oil. You remember Number 6 oil we had a boiler fuel rate where we would -- we would peg our -- our gas cost rate to try and get customers to switch from burning

Number 6 oil. We did that on a monthly basis. Number 6 oil doesn't exist in our service class -- in our service territory any -- any longer.

Number 2 oil was selling at a premium over -- over natural gas by maybe about 25%. Today it's like a 200, 300% premium over the price of natural gas. So competitive circumstances have -- have changed dramatically. Oh, one more thing happened too. Local production and -- and local production bypass was -- was a very big -- a big threat back then.

It has literally dried up. The -- the local produce -- producers are not producing out of the wells as -- as much as they had in the past, and we're seeing customers that have bypassed us -- the local production returning -- returning to the system. The one area that there still is competition and they -- the energy services panel talked about it is with -- with pipeline bypass. But a tool that back in -- in 1995 was perhaps 7 years old, our ability to flex and negotiate to meet that -- that bypass competition is now 25, 30 years old, and we have been able to effectively use that tool to -- to meet competition.

So there's a big change in circumstances over the last -- last 20 years as far as

competitive situations. And -- and how you should factor in and look at the results of a cost of service study or recognize that that when you're -- when you're replacing leak prone pipe that -- that benefits all customers because it provides continued access to the -- the lowest price natural gas in the world by, you know, a factor of 50, 60%.

Actually this -- this weekend our gas supply guys purchased gas at I think 25 cents and that's at a 90% discount over NYMEX. Now that was a -- a just a unique circumstance based on -- on what was happening in the marketplace. But -- but things have changed and all customers are benefiting from the access of -- to low-cost natural gas. And all customers benefit from the upgrade and modernization of the system. So we thought it was reasonable that all customers should share in the increasing costs of -- of upgrading the system.

Q. Okay. And -- and you mentioned that the energy services panel will be testifying later today on -- on the competitive threats that the company still does face. But you talked about -- you talked about the commodity price of gas. It's significantly lower than it has been historically. I think we can -- for purposes of this examination we can agree it's much lower than it was,

correct?

A. Yes.

Q. And you talked about how that should be considered when you're looking at a cost of service study, do you recall saying that a moment ago?

A. It's more the allocation of -- of rate increases --

Q. Well, let --

A. -- and rate designs.

Q. -- so let's -- let's -- let's explore that a second. Do you -- do you agree that mitigation of rate shocks to classes is a legitimate concern for the commission?

A. Yes. Yes.

Q. Okay. And all else being equal it's easier to correct cost of service imbalances during a period when the commodity prices are significantly lower than they would be, for instance, when commodity prices are significantly higher, would you not agree?

A. If -- if you're -- you're implying that -- that I would agree that now is the time to --.

Q. No, no, no, no. No, no, Mr. Meinl's, let's -- let's make sure you're answering my question not yours.

A.L.J. LECAKES: At the same time, Counsel, do let him answer the question to make sure that that's what he's doing before you interrupt.

MR. MAGER: Yes.

A.L.J. LECAKES: Thank you.

BY MR. MAGER: (Cont'g.)

Q. Let -- let's put aside your cost of service study in -- for this case. I'm just asking you on a general basis --.

A. I'm sorry. Am I hearing cost of service study or revenue -- or increase allocation?

Q. No, it's -- let's put aside cost of serve -- let's put aside your cost of service study and let's -- we can even put aside your cost of -- your revenue allocation proposal. I guess what I want to know is -- is it -- is it easier to -- to correct cost of service imbalances between classes during the period of low gas prices as compared to a period of high gas prices if one of your goals is to mitigate undue impacts on individual classes?

A. Mike, again, if I'm -- and forgive me if I'm not hearing you correctly, but I -- I believe you're suggesting that it is okay because prices are so low to change your proposed revenue allocation and

allocate more costs to residential commercial class and less to the large industrial classes.

Q. I -- I didn't suggest that at all in my question.

A. Okay. Then I -- then I misheard you.

Q. Yeah, I didn't use those words at all. You know, and I'll -- I'll move on. I think the point has been made.

Could you turn to page 24 of your rebuttal please?

A. (Crahen) Okay.

Q. And starting on line 13 you -- you state -- you cite to the commission's September 1995 order and you say -- and -- and the order states, no responsible rate analyst would rely wholly on an embedded cost of service study to set gas rates. But since your study does provide some guidance about the direction and magnitude of rate changes required to ensure that rates remain competitive, do you see that?

A. Yes.

Q. What do you think the commission was referring to after the semicolon in that sentence?

A. The way I'm reading it and interpreting it, the commission is referring to the fact

that the cost of service study is one of several considerations that can be looked at when, you know, when forming rate design or rate allocation across customer classes. That it's not just the cost of service study resolves itself.

Q. And -- and what type of guidance does the commission believe it provides -- what -- what is -- what do you understand when it -- when the commission says a study does provide some guidance about the direction and magnitude of rate changes required?

A. (Meinl) To ensure that rates remain competitive.

Q. Is that the only thing it means?

A. I don't know if there's -- there's more in the commission's mind with that sentence, but I think it's -- it's clear there that it's required to ensure that rates remain competitive. And I -- I think we just discussed how 1995 is very different than 2016.

Q. Do you think it's -- do you think equity among classes is relevant in revenue allocation decisions?

A. Yes, and I don't think we -- we -- I don't think we are inequitably treating any rate class in our proposal.

MR. MAGER: Thank you. I have nothing further, your Honor.

A.L.J. LECAKES: Ms. Jorgensen. Ms. Jorgensen.

MS. JORGENSEN: Thank you, your Honor.

Your Honor, would your preference be --? Would your preference be for me to submit and get marked for the record the additional exhibits pertaining to this cost of service rate design panel?

A.L.J. LECAKES: Do you have exhibits that you wish to question the panel on?

MS. JORGENSEN: No. We had -- the company and PULP had come to an understanding that they would be offering verbal stipulations on a number of their responses to IRs posed by PULP and 2 of which pertain to the cost of service panel. I'm happy to take them wholesale so that you could have a clean record for all the verbal stipulations on this disc or we can just take them in turn.

A.L.J. LECAKES: Why don't we do it afterwards if you're not going to be questioning the panel?

MS. JORGENSEN: Excellent.

A.L.J. LECAKES: We'll do it as soon

as the panel is done.

CROSS EXAMINATION

BY MS. JORGENSEN:

Q. Excellent. Thank you. Well, in light of their verbal stipulation and also the cross examination of both the other parties I actually have just one follow up question. If you could turn in your rebuttal testimony --.

MR. DELVECCHIO: Your Honor, just one item on the stipulation. I guess from the company's position the stipulation would be that, yes, these were IRs that were served upon the company and that these were the company's responses.

A.L.J. LECAKES: Right. I -- I do understand that as a stipulation --

MR. DELVECCHIO: Okay.

A.L.J. LECAKES: -- and that the company is not agreeing to anything further that PULP may represent --

MR. DELVECCHIO: Thank you.

A.L.J. LECAKES: -- about those IRs.

MR. DELVECCHIO: Thank you.

A.L.J. LECAKES: Ms. Jorgensen, your question or questions?

MS. JORGENSEN: Yes.

BY MS. JORGENSEN: (Cont'g.)

Q. So if you could go to the rebuttal testimony, page 82, lines 11 to 17.

A. (Crahen) Yes.

Q. Excellent. Here you are discussing a discovery response by PULP and is it correct that you're stating here that in response to one of your information requests PULP affirmed that the company does not control customer costs associated with buying or leasing a home, apartment or any other type of housing unit?

A. If -- if you refer to Exhibit 34 --.

Q. Well, actually I just wanted to start first with page 82, lines 11 to 17 and we'll -- and then we'll go right over to that exhibit next.

A. Okay.

Q. You're anticipating my next question. Okay. So could you just confirm that on page 82, lines 11 to 17 you characterized PULP's response as an affirmative one?

A. 11 through 17 we -- we talked about PULP's response to that data request affirming that the company doesn't control customer costs associated with buying and leasing a home. As part of a complete record,

we did include that exact response as Exhibit 34.

Q. Excellent. And in -- and in the Exhibit 34 do you have that in front of you right now?

A. Yes, I do.

Q. Okay. So in looking at the exhibit next to the testimony side by side today, would you agree that PULP did not provide the company with an unequivocal affirmative response? We, in fact, objected, said probably true and then we said that that's speculative because we have no basis for answering?

A. So the question for the record says would PULP agree that the company does not control the cost for a customer to buy or lease a home, apartment or any other type of housing unit. There's an objection by PULP and then PULP does indicate they're providing the following response which says probably true. And then you continue in the response to talk about that this could possibly be speculative in itself.

Q. Excellent. Thank -- thank you for clarifying that. I also wanted to just point out in the -- the exhibits, number 18, cost of service rate design 18. That has a number of responses that PULP gave. As far as I could tell in reviewing the rebuttal you make reference to 1 on page 87, lines 10 to 17 regarding

question 15. But the rest of those responses that are included in that Exhibit 18 are not -- they're in the -- they're in the record as one of the exhibits but they're not referenced in your testimony. So I just wanted to make sure that you're not attempting to put in all of the other answers or will be relying on those answers in your post trial briefs or any of that sort.

A.L.J. LECAKES: I'm -- I'm not sure and there's no objection, but I'm not entirely sure what the question is. Anything that's in an exhibit that's in the record is free to be used by any party in their post hearing briefs or in any post hearing documents. So I -- I don't -- especially of lay witnesses I don't think or -- or even expert witnesses, I don't think it's fair to be asking witnesses what their attorneys may or may not be planning to use in post hearing briefing.

MS. JORGENSEN: Oh, sure. Sure.

BY MS. JORGENSEN: (Cont'g.)

Q. Well, then I could just say in your testimony did you rely on any of PULP's other responses contained in that discovery set of questions --

A. So --.

Q. -- in -- in preparing your testimony?

A. So we're referring to Exhibit 18,

Schedule 2 there's a series of questions from the company. It's PULP as you noted and several of those questions are -- are all interrelated. You can't really take one out from the set because they're all interrelated. It -- it's all part and parcel.

All these questions do actually -- is they're asking -- and we asked them of all the parties. We didn't ask just PULP. We're asking if -- if the parties were aware of the benefits that accrued to customers in the company's service territory from Appalachian Gas. A -- a pricing phenomenon that's unique to customers in the company's service territory and based on Exhibit 18 not just Schedule 2 but all the schedules, none of the parties were aware of the pricing phenomenon that persists in the company's service territory at all. That all customers of all classes can benefit from.

Q. Okay. But in -- just in relation -- I don't want to speak for the other parties, but just in relation to the schedule that pertains to the questions and answers that you asked and that we answered on behalf of PULP, the only question that you actually cite in your testimony in support of your position is -- is the question 15 that you posed and we answered.

A. (Meinl) Well, we put these responses,

like Evan said, of all the parties in our cost of service and rate design testimony. But it also has -- has pertinent implications for the low-income panel, rates panel and the customer services panel. There's -- there is a wealth of information here that tells what parties know about our service classification and -- and what the -- the characteristics are of the most payment troubled, low-income customers in our service territory.

It's -- it was a -- a reasonable spot to place this exhibit. It relates to the cost of service study testimony and there are other -- other areas in the -- in the case where this -- this interrogatory I think will be helpful.

Q. I'm -- I'm happy to have you --.

MR. DELVECCHIO: Yeah, your Honor, the company would respectfully request that with respect to the interrogatories that we entered as exhibits, we do reserve the right to use any or all portions of them in -- in the briefing. That was our understanding with the purpose of the interrogatories without respect to whether the specific rebuttal testimony uses every single line in the interrogatory.

A.L.J. LECAKES: Yeah, I -- I -- I don't need to repeat, but I -- I will indicate that I was

trying to be clear before that anything that's in the record as an exhibit, whether it's mentioned in testimony, whether it's mentioned on cross examination, if it's an exhibit and it's marked then it's fair game for any party to be using that in post hearing briefing.

MS. JORGENSEN: I don't -- I don't mean to be obtuse, your Honor. The reason for my concern is based on the -- the clarification that we just made in regards to the way that PULP responded not unequivocally in the affirmation and it was characterized as some -- in other answers we've -- we've applied in the same sort of fashion where there was an objection and then a probably true or maybe likely.

A.L.J. LECAKES: Okay. Ms. --.

MS. JORGENSEN: And I'm -- I'm afraid -- I'm looking ahead and I'm afraid that --.

A.L.J. LECAKES: Yeah, but, Ms. Jorgensen, I -- I do understand that concern. Let me tell you right now in terms of post hearing briefing there's been no schedule established, but I did speak with Mr. Favreau and -- and asked him during the course of these 3 days to confer with the other parties about trying to get together a joint briefing schedule.

The schedule that Mr. Favreau and I

discussed briefly did contemplate a reply phase to the extent that the company characterizes exhibits in the record that PULP feels represented answers that the company may have or any other party may have interpreted wrongly or -- or incorrectly, PULP is certainly free to address that in -- in the reply briefing stage.

MS. JORGENSEN: Excellent. Thank you, your Honor.

MR. NICKSON: And I did -- I just for -- I sent an e-mail around this morning to the parties proposing 2 dates just before this hearing.

A.L.J. LECAKES: Do you have anything further?

MS. JORGENSEN: No, no further questions, your Honor. Thank you very much.

A.L.J. LECAKES: Mr. Ford.

MR. FORD: Thank you, your Honor.

CROSS EXAMINATION

BY MR. FORD:

Q. Just have a few more questions. I won’t repeat anything that Mr. Zimmerman asked about the appropriateness of including -- I won’t repeat anything Mr. Zimmerman said about the appropriateness of including the cost of gas mains in the customer charge.

Okay. These are my questions. If I divided my house into 2 apartments and had National Fuel install a second meter, would that increase National Fuel's billing costs by a dollar and 4 cents per month?

A. (Meinl) That would be the billing charge that you would be charged.

Q. Okay. Thank you. Would that increase National Fuel Gas's meter reading cost by approximately 92 cents per read or 46 cents per month?

A. (Crahen) Having 2 meters at a single residence would increase the company's costs of doing business to the extent that a -- an additional employee would be needed to perform that read.

Q. Okay. And I understand you can't have a separate price for every meter and you have to go by an average price.

A. Yeah, I guess with that point, I mean, when we're -- when we're looking at cost of service studies and rate design, we really need to consider balance. And it's -- and it's -- and you can't look at a single customer or single class of customers in isolation. You have to look at all customers with the large commercial and industrial customers, the residential customers, low-income customers and every other customer

in between.

It would be impractical to have a single rate on every single customer because there -- there could be instances to the extent that you do that that those rates would vulcanize the system to one customer's benefit and other customers would have to contribute to make whole**1**.

Q. Okay. Okay. I accept that. Would you agree that the meter reading cost in the cost of service study averages out to 92 cents per read when you divide by the 480,042 customers -- residential customers?

A. Can you give us a reference to our testimony where -- that you're referring to that cost?

Q. Okay. Do you have Exhibit 177 we gave out yesterday?

A. Is that -- is that your Exhibit, Mr. Ford?

Q. Yes. Yes. Second page of that.

A. (Meinl) I we don't -- we don't have that --

(Crahen) We don't have a copy.

(Meinl) -- that copy.

Q. Can someone -- anyone from --.

A.L.J. LECAKES: I do have an extra

copy if no one else has one. Does the company need an extra? You're -- you're comfortable? Okay. Thank you.

THE WITNESS: (Crahen) Thank you.

BY MR. FORD: (Cont'g.)

Q. Just -- just turn to the second page. Says the metering -- meter reading cost is 2,636,599 dollars divide that by the 480 dollars--.

A. (Meinl) I'm -- I'm sorry, Richard. You're not --.

Q. Under customer accounts about halfway down the page.

A. Can you -- which page is it again?

Q. Second page.

A. Second page?

A. Yes.

Q. It's about halfway down and see customer accounts.

A. (Crahen) Okay.

Q. And the amount you attribute to residential customers is 2,636,599 dollars, okay. And dividing that by the 480,042 customers and then by 12 months that gets you to 46 cents per customer per month. You agree with that?

A. (Meinl) Let me -- let me use my

calculator.

Q. Sure. Fine.

A.L.J. LECAKES: Mr. Ford, while the witness is doing that the number of customers that you're citing for the division that you're doing, are those residential customers only or total customers on the NFG system?

MR. FORD: Those are residential only.

A.L.J. LECAKES: Okay. Thank you.

A. (Crahen) And -- and you -- excuse -- did you say divided by 12 as well --

BY MR. FORD: (Cont'g.)

Q. Yes.

A. -- for the months? Divide by 12? So the math works out to be 41 cents. However, subject to check if these are even the company's numbers since they're not the company's exhibit.

Q. The numbers were taken from the slides **you --.**

A.L.J. LECAKES: I'm -- I'm appreciative of that. Of -- of both positions in this.

BY MR. FORD: (Cont'g.)

Q. Do you get 40 -- 41 cents? I get 46 cents. Okay. With a capital maintenance cost of the new

meter, averages out to 75 cents per month over time.

A. (Meinl) So what's -- what was the -- the reference?

Q. Okay. This went over --.

A. Is it capital maintenance cost?

Q. Fourth page --

A. (Crahen) Okay.

Q. -- fourth page of that same exhibit. Company lists a cost of 4,324,392 dollars for meters and house regulators.

A. Okay.

Q. And divide that by the 480,042 customers and by 12 months you get 75 cents?

A. (Meinl) I'm -- I'm just trying to -- to understand what that number is. You said capital and maintenance cost. Do you mean operation maintenance cost? Because when I -- when I -- I previewed an exhibit that you had sent out earlier in the case, and I believe you updated it. And it appeared that you excluded all the -- the capital costs associated with main lines, service lines and associated depreciation from your analysis.

Q. Right.

A. So I'm -- so to the extent there's a meter that we installed in a house, I didn't see any --

any capital recovery of -- of that meter. To the extent there was a service line to that house, I didn't see any capital costs associated with that service line and associated depreciation in income taxes. So it's my understanding that all the costs in your exhibit represent operations and maintenance costs.

So I just wanted to make sure that I understand that these are O and M costs only.

Q. Correct me if I didn't understand the terminology in your -- your Exhibit COSD - 1, but you labeled it as meters and house regulators.

A. Right. And my understanding that's the operation and maintenance portion of those -- of those costs.

Q. Okay. So the -- the additional --

A. So we have to go out --.

Q. -- costs for the capital costs?

A. Well, these are actually capital. Yeah, the -- the cost of the meter itself that gets installed and -- and put into service.

Q. Okay. So -- so I get 75 cents and that would be operation for maintenance only. Okay and you've answered my next question. Well, adding those 46 cents and 75 cents gets us to 1 dollar and 21 cents, an

additional cost from installing a second meter. And there should be a capital cost added to that. Can you think of any other ways in which adding a second meter at my house would increase the cost of National Fuel?

A. I think that would -- that would cover it.

(Crahen) Yeah, I mean the only other thing would be, you know, is it sharing the service line that connects to the main line? Would it have its own dedicated service line? There's a number of factors that would -- that would go into that consideration without having a -- a specific specification that's hard to speculate what, you know, what the costs might be for one individual customer for that customer's unique circumstances.

Q. Okay. So if a customer does not pay his bill and you have to shut off his service, do you read the meter anyway to make sure there's been no unauthorized opening of valves?

A. I -- I presume that we do.

Q. So when a customer has been shut off how much does the fixed cost go down for National Fuel?

A. (Meinl) Not at all. Definition of fixed costs it wouldn't at all.

Q. Okay.

A. The service line is still there, the main line serving that customer is still there. The meter it's still there. It's locked but -- but still there.

Q. Okay. And thank you. I have a few questions about the customer service costs which the company includes in the customer service charge. Has National Fuel ever gotten a complaint call to customer service about an estimated usage that was 175% too high?

A. I'm -- I wouldn't know --

(Crahen) Don't know.

(Meinl) -- what complaints we've received. I do know we do receive complaints from time to time and a reasonable amount.

Q. So you wouldn't know if you also got complaints about false information about the sales tax on the bill?

MR. DELVECCHIO: Going to object to that, your Honor. There's really no foundation for alleged false sales tax.

A.L.J. LECAKES: I under -- yeah, I can appreciate that. I -- I didn't take the question as --

MR. FORD: Well --.

A.L.J. LECAKES: -- excuse me, Mr. Ford, just a moment. I -- I didn't take the question, Mr. DelVecchio as a necessarily established allegation. It was more directed to do the witnesses have knowledge of any complaint made about anything regardless of the validity of the complaint or not, so.

MR. DELVECCHIO: Understood.

A.L.J. LECAKES: It's -- and -- and do those -- the witnesses have any knowledge of any such complaint?

THE WITNESS: (Meinl) Well, I -- I -- I do have general knowledge that Mr. Ford has called our service center and talked to our -- our customer service representatives. So if there was a complaint, a specific complaint with that, I don't know.

A.L.J. LECAKES: Okay.

THE WITNESS: (Crahen) And from my end just general knowledge it -- it's possible the company may have received complaints from customers about an increased temporary state assessment charge --

A.L.J. LECAKES: Okay.

THE WITNESS: -- which would be related to taxes.

A.L.J. LECAKES: Okay.

THE WITNESS: But that's the only thing I would have --.

BY MR. FORD: (Cont'g.)

Q. Since both of you live in Erie County do you believe that Erie County imposes a -- ever imposes a 17% sales tax on the supply cost of gas?

A. That's a question for Erie County.

Q. Do you get bills yourself?

A. (Meinl) I -- I do not believe the sales tax rate in Erie County is -- for gas service is 17% on a residential customer.

Q. Okay. Has the customer service department ever gotten a complaint from customers who use less than 2 dollars' worth of gas and got billed for over 20 dollars?

A. I -- I don't know.

(Crahen) I'm not aware of any complaints of that type.

Q. Okay. Okay. Is it the company's position that customers should be required to pay extra because of these problems that National Fuel brought on themselves?

A. To clarify I don't think that there's any problems -- that kind of -- I guess to the point, I'm

-- I'm not quite sure what the question's leading to. I don't think the company has done anything to indicate a problem. In fact, I think the company provides safe, reliable natural gas services at just and reasonable rates to all of its customers 24 hours a day 7 days a week.

Q. But do you get some complaints?

A. In fact, if you want to look back at our PSC complaint rate, I think, you know, there was a period of time, 18 months where we hadn't had a single complaint for a customer. In fact, we've been quite the leader in New York State. The customer service panel who's going to be here tomorrow can elaborate on that further, but I -- I think we're a leader in New York State with respect to complaint rates from customers.

(Meinl) Yeah, when you -- when you talk complaints I was -- I was assuming you were talking about a customer talking to our reps and complaining about something on their bill.

Q. Yes.

A. But as Evan says, the -- the definition of a complaint to the commission we've had zero -- zero complaints for a long -- a long time.

Q. Okay.

A. We work hard to -- to make sure that

we resolve problems with customers.

Q. Thank you. My house is located on Route 78 and I'm surprised to come to Albany to hear my neighborhood discussed here today, but. Last year I used 120 dollars' worth of gas. If I decide to move further into the country and build a similar house that also uses 120 dollars' worth of gas a year, would National Fuel be willing to install a -- a mile of minimum sized pipe to reach my house and sell me another 120 dollars' worth of gas?

A. Our tariff allows you 100 feet of main line and 100 feet of service line at no additional charge. Anything beyond that 100 feet you would have a surcharge based on your expected consumption.

Q. Okay. Thank you. Oh, based on expected consumption. Could you repeat that? Did you say based on expected consumption?

A. Yes. Yes.

Q. Thank you. I guess Mr. Meinl's answer kind of sums up the whole position so.

A.L.J. LECAKES: Great. Thank you, Mr. Ford. Staff at this point any cross examination come up while you were listening to the other parties? Company approach the witnesses if you want and discuss redirect.

We'll take a few minute break off the record while the company discusses.

(Off the record)

MR. DELVECCHIO: Your Honor, the company has no redirect.

MR. DELVECCHIO: Thank you, Mr. DelVecchio. Both these witnesses will remain under oath since you both have testimony coming up. Why don't we take a few minute break? What we'll do is I believe -- I do know that Mr. Sano is here in the building so while staff gets him down here we can set up the energy service panel and move right to them so that Evan can out here -- out of here before lunch hopefully.

MR. CRAHEN: Thank you, your Honor.

A.L.J. LECAKES: All right. Thank you. We'll take a -- a break while the energy service panel gets together. We're off the record.

(Off the record)

A.L.J. LECAKES: NFG please call your next panel.

MR. NICKSON: Company calls its Energy Services Panel consisting of Robert D. Eck, Erik M. Solomon, Evan M. Crahen and Clifford J. Mason.

A.L.J. LECAKES: Okay. Panel members

-- Mr. Crahen, you already identified yourself earlier. Could the other panel members please identify themselves for the record by name and business address please?

MR. SOLOMON: Erik M. Solomon, 6363 Main Street, Williamsville, New York.

MR. ECK: Robert D. Eck, 6363 Main Street, Williamsville, New York

A.L.J. LECAKES: All right. Mr. Solomon and Mr. Eck, could you please stand and raise your right hand? Do you swear or affirm that the testimony you're about to give today is the whole truth?

MR. SOLOMON: Yes.

MR. ECK: Yes.

ERIK SOLOMON; Sworn

ROBERT ECK; Sworn

A.L.J. LECAKES: Thank you. You may be seated. Mr. Nickson, proceed.

DIRECT EXAMINATION

BY MR. NICKSON:

Q. Panel, do you have in front of you a document entitled direct testimony of the Energy Services Panel consisting of 86 pages of questions and answers?

A. (Eck) Yes, we do.

Q. And was that document prepared by you

and under your supervision?

A. Yes, it was.

Q. Do you have any changes or corrections to your testimony?

A. (Solomon) No.

Q. If I were to ask -- if I were to ask you the same questions today would your responses be the same?

A. (Panel) Yes.

Q. And do you adopt this testimony as your sworn testimony in this proceeding?

A. Yes.

MR. NICKSON: Your Honor, I ask that the direct testimony of the Energy Services Panel be incorporated into the record as if given orally today.

A.L.J. LECAKES: Granted. At this point in the transcript the Energy Service Panel direct testimony file and the Company Direct Testimony folder should be added into the transcript.

DIRECT TESTIMONY OF ENERGY SERVICES PANEL

1 **Section 1 - Introduction**

2 Q. Please introduce the members of this Energy Services Panel.

3 A. We are Robert D. Eck, Erik M. Solomon, Evan M. Crahen, and
4 Clifford J. Mason.

5 Q. Mr. Eck, please state your business address.

6 A. My business address is 6363 Main Street, Williamsville, New York
7 14221.

8 Q. By whom are you employed and in what capacity?

9 A. I am employed by National Fuel Gas Distribution Corporation
10 ("Distribution" or "the Company") as the General Manager of the
11 Energy Services Department.

12 Q. Please state briefly your educational and professional experience.

13 A. I graduated from the University of Vermont in 1982 with a Bachelor
14 of Science Degree in Mechanical Engineering. I also received a
15 Masters Degree in Business Administration from the State University
16 of New York at Buffalo in 1990. I began my employment with
17 Distribution in September 1984 as a Technical Services
18 Representative in Commercial and Industrial Sales. Since that time,
19 I have held various managerial positions associated with technology,
20 market research, sales and marketing. In March 2015 I was

1 promoted to General Manager with responsibility for all sales and
2 marketing functions in the Energy Services Department, for our New
3 York and Pennsylvania Divisions.
4 Q. Have you presented testimony before any regulatory commissions?
5 A. Yes. I have presented testimony before the New York Public Service
6 Commission ("Commission") pertaining to our sales, marketing,
7 energy efficiency and research, development and demonstration
8 programs.
9 Q. Mr. Solomon, please state your business address.
10 A. My business address is 6363 Main Street, Williamsville, New York,
11 14221.
12 Q. By whom are you employed and in what capacity?
13 A. I am employed by Distribution as a Senior Manager in the Energy
14 Services Department.
15 Q. Please state briefly your educational and professional experience.
16 A. I graduated from the State University of New York at Buffalo in 1998
17 with a Bachelor of Science Degree in Business Administration. I also
18 received a Masters Degree in Business Administration from St.
19 Bonaventure University in 2003. I began my employment with
20 National Fuel Gas Supply Corporation in June 1998 as a

1 Transportation & Exchange Representative. Since that time, I held a
2 position for Distribution in the Gas Supply Administration Department
3 with responsibility for gas procurement, off-system sales, capacity
4 release and gas scheduling. In 2005, I transferred to the Energy
5 Services Department as a General Energy Consultant, with
6 responsibility for large volume assigned account sales and customer
7 service. In 2014, I was promoted to Senior Manager, with
8 responsibility for sales, marketing, customer service, and economic
9 development functions in our New York Division.
10 Q. Mr. Crahen, please state your business address.
11 A. My business address is 6363 Main Street, Williamsville, New York
12 14221.
13 Q. By whom are you employed and in what capacity?
14 A. I am employed by Distribution as a Regulatory Analyst II in the Rates
15 and Regulatory Affairs Department.
16 Q. Please state briefly your educational and professional experience.
17 A. I graduated from Canisius College in December 2006 with a
18 Bachelor of Science degree in Economics and Finance. In January
19 2007, I began my employment at a Fortune 1000 financial institution
20 as an Accountant/Financial Analyst. In December 2008, I earned a

1 Master of Business Administration degree from Canisius College. In
2 January 2009, I joined Distribution as a Management Associate in
3 the rotational training program. While in the program, over the
4 course of 2 years I spent rotations with the Human Resources
5 Department, the Investor Relations Department, the Corporate
6 Communications Department, and the Accounts Payable
7 Department. In May 2011, I was promoted to Regulatory Analyst in
8 the Rates and Regulatory Affairs Department, upon the successful
9 completion of the rotational training program. In March 2014, I was
10 promoted to Regulatory Analyst II, my current position.
11 Q. Have you presented testimony before any regulatory commissions?
12 A. Yes. I have presented testimony before the Pennsylvania Public
13 Utility Commission pertaining to purchased gas costs.
14 Q. Mr. Mason, please state your business address.
15 A. My business address is 6363 Main Street, Williamsville, New York
16 14221.
17 Q. By whom are you employed and in what capacity?
18 A. I am employed by Distribution as a Senior Manager in the Energy
19 Services Department.
20 Q. Please state briefly your educational and professional experience.

A. I graduated from the State University of New York at Canton in 1978 with an Associates of Applied Science Degree in Air Conditioning Technology. I also received a Bachelor's Degree in Energy Engineering Technology from Rochester Institute of Technology in 1984. I began employment with Distribution in January 1988 as a Conservation Supervisor. Since that time, I have held various positions developing and managing low income weatherization and payment assistance programs. I also have experience in our Operations area, specifically as a New Service Representative and Meter Reading Supervisor. Since 2005 I have been employed in the Energy Services Department as a commercial/industrial account representative. In 2014, I was promoted to Senior Manager, with responsibility for residential marketing and natural gas vehicle marketing in our New York Division.

Section 2 – Opening/Purpose of Testimony

Q. What is the purpose of the Energy Services panel testimony?

A. The purpose of the Energy Services panel testimony is to describe:

(1) the competitive situation for large volume customers, including:

- pipeline bypass competition;
- oil and coal competition;

- electric competition; and
- other competitive factors.

(2) the energy efficiency and growth activities for large volume customers, including:

- Gas Technology Program and Distributed Generation ("DG") Pilot Program;
- Research, Development and Demonstration ("RD&D") Program;
- Economic Development Program and Area Development Program ("ADP");
- PRIME-WNY Pilot Program;
- Reforming the Energy Vision ("REV") activities; and
- Telemetering.

(3) the energy efficiency and growth activities for small volume customers, including:

- Conservation Incentive Program ("CIP");
- Gas Network Enhancement Program ("GNEP"); and
- Natural Gas Vehicles ("NGV's") and NGV Pilot Program.

Section 3 – Competitive Situation, Large Volume Customers

Q. Please describe the competitive environment in Distribution's markets.

A. Distribution is affected by a variety of market forces. The most obvious form of competition is interfuel competition (gas to oil, gas to gas, gas to electric, and gas to coal). This kind of interfuel competition occurs primarily in our larger commercial and industrial customer markets.

Q. How does Distribution compete with the various forms of interfuel competition?

A. Distribution approaches interfuel competition from two perspectives; namely, burnertip pricing strategies and a technology strategy. Our burner tip pricing strategies incorporate all the available rate structures of our tariff with the majority of the emphasis on transportation programs. Our objective is to work closely with our end-users to enable competitive pricing strategies to be developed such that the end result is retaining and, in some cases, increasing throughput on Distribution's system. Introducing our customers to new, high efficiency technologies also assists us in addressing interfuel competition. Our customers benefit by realizing lower

1 energy costs and higher efficiencies in plant production. The net
2 result is our customers become more efficient and competitive in
3 their business sectors, thereby helping to retain and, in some cases,
4 increase throughput on Distribution's system.
5 Q. Why is it important for Distribution to retain and increase throughput
6 on its system?
7 A. By retaining existing throughput, and selectively increasing
8 throughput where possible and consistent with sound practices,
9 Distribution is able to help spread the fixed costs of operating our
10 system over a larger base, thereby reducing the cost of service to all
11 our customers.
12 **A. Pipeline Bypass Competition**
13 Q. Does Distribution face competition from pipeline bypass?
14 A. Yes, very much so.
15 Q. What types of pipeline bypass are present in the Company's area?
16 A. We are experiencing two types of pipeline bypass: natural gas
17 pipeline bypass and steam/hot water pipeline bypass.
18 Q. How does Distribution compete against a natural gas pipeline bypass
19 threat?

1 A. Generally customers that are considering natural gas pipeline
2 bypass are currently transportation customers on Distribution's
3 system. Distribution's tariff provides for flexibly priced transportation
4 service. Because natural gas pipeline bypass is largely a function of
5 economics, the willingness of a customer to remain on our system
6 depends on our ability to meet its economic requirements by offering
7 a rate that is competitive with the potential bypass.
8 Q. What types of natural gas pipeline bypass threats exist?
9 A. Natural gas pipeline bypass can be categorized into two categories;
10 namely, 1) bypass to a pipeline; and 2) bypass to locally produced
11 natural gas.
12 Q. Please explain each type of natural gas pipeline bypass.
13 A. Bypass to a pipeline is simply a line being built directly to an
14 interstate or intrastate pipeline, such as the Tennessee Gas Pipeline,
15 bypassing Distribution's local system.
16 Bypass to locally produced natural gas is a bypass pipeline to a local
17 production natural gas well or to a local production pipeline gathering
18 system.
19 Q. How does Distribution evaluate the various natural gas bypass
20 threats?

A. Each type of pipeline bypass offers different characteristics of service. It is important that our customers understand the service levels of each pipeline type, as key services such as balancing provisions can have a significant impact on the reliability and pricing of supply. Distribution also considers such factors as geographic location of the customer relative to the bypass pipeline source, the size of the customer in terms of annual volume and margin, load factor, and, lastly, facilities cost.

Q. What is the estimated Mcf volume impact to Distribution as a result of the natural gas pipeline bypass threat?

A. The bypass threat is very real. Distribution estimates that the current existing annual load loss to bypass (either total or partial bypass) is 3,598,000 Mcf. This load loss comes from 7 customers (2 large volume and 5 smaller volume customers). In addition, there is load that is potentially at risk to bypass. Distribution estimates there are 22 customers with approximately 6,208,020 Mcf of load that can be categorized as "high risk". There are also 21 customers with approximately 4,235,683 Mcf of load that can be categorized as "medium risk" and 43 customers with approximately 1,370,255 Mcf of load that can be categorized as "low risk". The total exposure of all

1 the natural gas pipeline bypass risk categories is 86 customers with
2 a total load loss of 11,813,958 Mcf. This does not reflect the
3 aforementioned 3,598,000 Mcf from the 7 customers that have
4 already bypassed Distribution. Natural gas marketers/producers are
5 actively seeking bypass opportunities, are offering to build pipeline
6 facilities and, in some cases are offering shared savings
7 agreements. Again, bypass is a significant concern because it
8 adversely affects the remaining customers on Distribution's system
9 by placing on the remaining customers the responsibility for the
10 revenue lost to the bypass.
11 Q. Please describe the steam and hot water pipeline bypass threat.
12 A. This type of bypass is essentially thermal energy pipeline bypass,
13 whereby a thermal energy source provides steam or hot water to end
14 users via a bypass pipeline.
15 Q. Please provide some examples of a steam or hot water bypass
16 pipeline threat.
17 A. One example would be the steam line that was built from a large
18 electric power generation facility, to several customers in the Niagara
19 Falls area. In this case, waste products are burned in a large boiler
20 and the thermal energy from the process is recovered and used to

1 produce steam, which is then piped directly to customers' facilities.
2 Currently that system is serving six (6) customers and could expand
3 further, due to the excess steam capacity it has available. Another
4 example of a thermal energy pipeline bypass is in the City of
5 Jamestown where thermal energy is produced from the electric
6 generation process and is used to produce hot water, which is piped
7 to a district heating system in the city. Currently the Jamestown
8 District Heating System serves 73 commercial/industrial customers
9 and could possibly expand. The expansion would likely occur using
10 satellite boilers fueled by natural gas that may be provided by a
11 bypass pipeline. Expanding the district heat system in this manner
12 could place the entire City of Jamestown at risk for Distribution, and
13 could result in significant revenue loss.
14 Q. Are there other thermal energy pipeline bypass threats in
15 Distribution's territory?
16 A. Yes, the City of Buffalo District Heating System could also put
17 substantial load at risk. The City of Buffalo District heating plant
18 currently serves six (6) commercial customers. The City of Buffalo
19 Energy Master Plan calls for the optimization of the district heating
20 plant. The district heating plant is estimated to be running at

1 approximately 33% of capacity. If expanded, the system could put
2 approximately another twenty (20) commercial customers at risk.
3 Q. What is the Company's load loss from these sources of steam and
4 hot water pipeline bypass?
5 A. We estimate we have lost approximately 4,520,000 Mcf per year to
6 the Niagara Falls bypass. As for the Jamestown District Heating
7 System, we estimate that we have lost approximately 62,000 Mcf per
8 year. We estimate we have lost approximately 50,000 Mcf per year
9 to the City of Buffalo District Heating System. Overall, the steam and
10 hot water pipeline bypass threat has resulted in an annual load loss
11 of 4,632,000 Mcf per year.
12 Q. How does Distribution evaluate and compete with this form of
13 pipeline bypass?
14 A. We evaluate and compete with the thermal energy bypass the same
15 way we do with the natural gas pipeline bypass threat, which we
16 discussed previously in this testimony. Pipeline bypass, in whatever
17 form, is a serious threat to Distribution's revenue base. Distribution
18 closely monitors this form of competition because once the bypass
19 pipeline is in place, the investment has been made and the revenue
20 will likely be lost to Distribution forever.

1 **B. Oil and Coal Competition**

2 Q. What is the nature of oil and coal competition in Distribution's
3 territory?

4 A. Oil and coal competition with natural gas in Western New York is
5 prevalent primarily in industrial, commercial and public authority
6 customer boiler applications. With the uncertain availability and the
7 rising prices of natural gas in the 1970s and 1980s, some of our
8 larger customers sought the flexibility and the perceived security of
9 boilers with alternate fuel capability, while other customers installed
10 alternate fuel capability during the gas moratorium period as required
11 by state regulations. Residual (No. 6) oil boiler installations
12 proliferated because of the relatively low cost of that fuel and its
13 availability locally. The supply of No. 6 oil is distributed from
14 refineries in Ontario, Canada; Detroit, Michigan; and Warren,
15 Pennsylvania. Major distributors price No. 6 Oil competitively
16 against each other and against natural gas. Oil is shipped directly
17 from refineries to customers or stored locally at terminals for future
18 delivery to customers. Coal boiler installations have been installed to
19 a much lesser degree than No. 6 oil, however they are still operating
20 and can be competitive with natural gas.

1 Q. Has the nature of oil and coal competition changed over the past
2 several decades?
3 A. Yes. Several factors have impacted this market and our customers
4 over the last few decades. One major factor is the increasing level of
5 federal and state environmental regulations on boiler emissions and
6 air quality, and the associated costs of non-compliance with these
7 regulations. Another major factor is the ample supply of very low
8 cost natural gas from the Marcellus shale formation available to
9 these customers. Still another factor is the involvement of
10 Distribution with our dual fuel customer base to educate them on the
11 hidden costs of burning No. 6 oil, and the resulting overall "true
12 costs" of burning oil beyond the commodity cost alone. Due to these
13 factors, many customers have removed the dirtier, higher cost No. 6
14 oil and coal capability in their boilers, and/or converted their boilers
15 to lower cost, cleaner burning natural gas. This trend has resulted in
16 a drop in the number of customers actively using No. 6 oil or coal in
17 their boilers. Distribution currently has only approximately 20 large
18 commercial/industrial customers remaining with working dual fuel
19 capability in their boilers, utilizing either No. 6 Oil or Coal, along with
20 natural gas. Distribution does still have a relatively large amount of

1 customers with No. 2 oil capability in their boilers, but this is mainly
2 among critical care facilities such as hospitals and nursing homes
3 that use this as a secondary backup energy source, and use natural
4 gas as their primary fuel. Therefore, currently the threat from these
5 alternate fuels has been effectively minimized at the present time.
6 However, market conditions could change in the future with respect
7 to environmental regulations and/or fuel commodity pricing. If this
8 occurs, Distribution is well suited to compete against both of these
9 fuels.

10 Q. How does Distribution compete against oil and coal?

11 A. Distribution competes with the oil and coal market largely through its
12 transportation service rates. Most customers who have oil or coal
13 capability are unwilling to execute a long-term contract and choose
14 to price their energy commodities on a short-term basis. Natural gas
15 marketers strive to provide competitive natural gas commodity
16 pricing to meet the aggressive oil and coal commodity pricing.

17 **C. Electric Competition**

18 Q. Does Distribution experience competition from electricity?

19 A. Yes. Distribution experiences competition from electricity in a
20 number of different market segments and end-use applications.

Electricity is very competitive in the industrial market segment and is used in a number of different end-use applications. Electricity from the New York Power Authority ("NYPA") is the most competitive source of electricity to the industrial market segment. Pricing is usually in the range of 1¢ to 2¢ per Kwh or on an equivalent Btu basis, $2.93 to $5.86 per Mcf. Competition in the commercial and public authority segments is increasing in recent years. Electric closed loop, water source heat pump systems are increasingly becoming the heating and cooling system of choice for new office buildings, schools and medical facilities. The efficiencies of these systems are high, with Coefficients of Performance ("COP") for heating in the range of 3.7 to 4.5. Heat pump COP is a measure of the efficiency of a heat pump in the heating mode. Conventional electric resistance heating is 100% efficient at the point of use, and natural gas heating systems have combustion efficiencies in the range of 80 to 95% at the point of use. However, heat pumps do not convert electric energy directly into heat. The electric compressor, or "pump", is used only to transfer the heat from a source (air, ground or water) to its destination, the heated space. Therefore, a heat pump with a COP of 4.0 transfers, or "pumps" four times more

energy to the heating space than the electric energy required to run the compressor. Properly sized ground source heat pumps do not typically require supplemental heating systems. However, water source (and air source) heat pumps usually require a supplemental heating system. In the case of the growing emergence of closed loop water source heat pumps, natural gas simply provides the supplemental energy for the very cold days in the winter when the heat pump system does not have the capability to meet the building energy requirements, and Distribution loses the heating load in the warmer shoulder months of the Fall and Spring.

Q. How does Distribution compete against electricity?

A. Given the low commodity pricing of power from NYPA, it is difficult for natural gas to be competitive. Distribution's focus is to apply technologies such as engine drives to individual end-use applications with customers that do not have an allotment of NYPA power sufficient to meet their entire load. End-use applications such as water pumping, air compression and cooling/refrigeration are ideal for the application of natural gas driven engines. On a more limited basis, distributed generation ("DG") may be a viable technology. Customers with high electrical load factors and good thermal host

1 characteristics are good candidates for this technology. The DG
2 market is more limited largely because of expensive electric standby
3 rate charges associated with the customer remaining on the power
4 grid. As a result, in some cases, DG projects in Distribution's
5 territory have been isolated from the power grid to avoid these
6 charges. Common applications of DG in our market include schools,
7 healthcare and industrial.

8 **D. Other Competitive Factors**

9 Q. Are there other factors affecting Distribution's sales?

10 A. Yes there are. While manufacturing is still an important part of the
11 local economy, Western New York has been transitioning from
12 manufacturing to the service industry. To the best of our knowledge,
13 there have been approximately twelve (12) major plant closings in
14 the past five (5) years. The impact of this transition has dampened
15 the growth in throughput in the manufacturing sector. Distribution's
16 commercial and industrial customers also are actively involved in
17 implementing conservation measures to reduce building heat loss,
18 and new equipment technology is being utilized to provide for greater
19 efficiencies in space heating and process applications. As energy
20 costs rise, there is greater economic incentive for customers to

investigate these measures to reduce costs. As customers take these steps to reduce their costs, Distribution's annual throughput declines. Today's new construction standards are much more energy efficient than in years past. Better construction materials, more insulation and more efficient space heating equipment all contribute to reduced throughput. For example, the efficiency of space heating equipment has increased from 80% to well over 90%.

Section 4 – Energy Efficiency and Growth Activities, Large Volume Customers

Q. What energy efficiency and growth initiatives does Distribution conduct among its large volume customers?

A. Distribution has four account reps in its New York territory, assigned to cover approximately 400 of our large volume accounts greater than 12,000 Mcf/year. These customers operate in very competitive markets and have many choices for their energy needs. The reps are assigned specific geographic areas to cover and they assist our large Commercial/Industrial customers in assessing various gas technologies that would make these customers more energy efficient. They work on a one-on-one basis with these customers to collect energy usage data, and utilize the services of our in-house

engineering staff to provide free technical and economic assessments of gas technologies that best fit the customer's energy needs.

A. Gas Technology Program and Distributed Generation Pilot Program

Q. What types of technologies does Distribution analyze to help make its large customers more energy efficient?

A. There are three main types of technologies Distribution assesses for its large customers. The first type is converting customers' space heating, water heating and process heating equipment to gas. Our engineers provide free estimates on the equipment capital cost, annual savings and simple payback for such conversions. The benefits to customers of these conversions include reducing their annual energy costs and making them more energy efficient compared to their alternate fuel. This is even the case with electric conversions. Even though electricity is 100% efficient at the point of use, the entire electric generation process from power plant, through transmission/distribution lines, to the point of use is very inefficient; ranging in efficiency between 30 – 35%, overall. Conversely, gas equipment, even though only around 80% efficient at the point of

use, is much more efficient overall than electricity, even after factoring in the transmission/distribution losses of natural gas pipelines. The last benefit to customers from these conversions is the environmental benefit; not just to the customer, of course, but to our entire society. These conversions result in cleaner air quality by reducing the burning of fuels such as oil and coal in both the point of use equipment, as well as in central power plants for electric conversions.

Q. What are the other two technologies that Distribution analyzes to help make its large customers more energy efficient?

A. Distribution also provides free technical/economic assessments for gas engine-driven technologies and distributed generation ("DG"). As mentioned earlier, engine-driven technologies include air compression, cooling/refrigeration and water pumping. These technologies involve replacing compressors, chillers and pumps driven by electric motors with gas engines. The waste heat generated by these engines is then available for the customer to use as a "free thermal energy" to displace some of their existing energy sources such as gas, oil or coal needed to make steam, hot water or hot air. This captured thermal energy can be used in space heating,

1 water heating, process heating, and in some cases even for space
2 cooling or process cooling. By capturing this waste energy, these
3 engine driven technologies can be significantly more energy efficient
4 than their electric motor driven alternatives. With good utilization of
5 the waste heat, engine driven technologies can approach overall
6 energy efficiencies of 70 – 80%, much greater than the 30 – 35%
7 overall efficiencies of electric motor technologies. These greater
8 efficiencies translate into reduced energy costs for our customers,
9 helping to make them more competitive and profitable.
10 Q. How does DG make customers more energy efficient?
11 A. DG is the generation of electricity on-site, at or near the point of use,
12 as opposed to purchasing electricity generated at a central power
13 plant many miles away. Technologies such as micro-turbines,
14 engines, and combined cycle turbines are used to generate power
15 onsite using natural gas. Like engine driven technologies, they also
16 capture the available waste heat to create steam, hot water, or hot
17 air for use in space heating, water heating, and process heating
18 applications. These systems also can approach 70 – 80% overall
19 annual efficiencies with good utilization of the waste heat, much
20 greater than the 30 – 35% overall efficiencies if purchasing power

from central power plants. The benefits of DG using natural gas are numerous. They can help customers become more energy efficient and lower their overall energy costs. Also, because the power is created near the point of use and not transmitted across above-ground transmission/distribution lines, the reliability of this power can be much greater since it is not affected by ice storms, wind, falling trees, etc. Finally, like engine drive technologies, they reduce the environmental impact of fuels such as oil and coal in central power plants, replacing them with clean burning natural gas. This reduces the harmful emissions from oil and coal, enhancing our environment and the quality of our air.

Q. How successful has Distribution been in working with its customers to install DG in its territory?

A. As of March 2016, Distribution currently has 19 DG/Combined Heat and Power ("CHP") customers. These installations include 1 microturbine, 14 engines, 3 gas turbines and 1 steam turbine. Total operating capacity for these 19 generators is 201 MW, with annual gas consumption in calendar year 2015 of 4.3 Bcf. The three largest of these 19 customers have electric operating capacities from 56 – 72 MW, and provide grid support to National Grid by selling the

power they generate back to the electric grid. The remaining 16 smaller customers have electric operating capacities from 120 to 6,000 KW, and do not sell their power back to the electric grid, but instead use the power they generate "inside the fence" within their facility. Also, of these 16 smaller customers who use the power they generate themselves, 12 are connected to the electric grid and operate in parallel with the grid, and 4 are disconnected from the electric grid and operate isolated and independent of the grid.

Q. Is Distribution involved in any microgrid or community DG projects in its territory?

A. Distribution has provided letters of support for three regional microgrid projects as part of NYSERDA's New York Prize ("NY Prize") Program. Distribution has been an active participant in the NY Prize project currently being proposed by the Buffalo Niagara Medical Campus ("BNMC"). As part of that project, Distribution has funded a study analyzing thermal loads throughout the campus and demonstrating the feasibility of utilizing CHP to provide both steam and power to the campus's main critical care facilities. Distribution believes that a successful project of this scale and prominence will

energize the market for DG and CHP, and should result in increased adoption throughout the region.

Distribution is also an active participant in the Proceeding on Motion of the Commission to Enable Community Choice Aggregation Programs (Case 14-M-0224) and the Proceeding on Motion of the Commission as to the Policies, Requirements and Conditions For Implementing a Community Net Metering Program (Case 15-E-0082). The Company looks forward to continuing its participation in the proceedings. In addition, to the extent that DG or CHP opportunities present themselves, Distribution looks forward to working with interested parties or stakeholders in actively pursuing potential projects.

Q. What are the current market barriers to increasing the amount of DG installations in Distribution's territory?

A. There are several barriers to increasing the adoption of DG in our service territory. The first is the high capital cost of the DG equipment, which can easily be several million dollars when design, engineering, equipment and installation costs are all included. This high cost must then be overcome by the annual energy savings generated from the project, and the resulting payback must be able

to meet the customer's investment criteria, which varies by customer type but can often be 3 to 5 years or less. The second barrier is the need for a customer to have rather large, year round thermal load to take advantage of the "free" thermal energy from the DG project. Without the presence of a good thermal load, the economics of DG projects tend to be poor. This tends to make DG a niche market technology, primarily focused on the best typical DG candidates, such as industrial customers, hospitals and nursing homes, which usually have a fairly large and steady thermal load. The third obstacle to DG is the high cost of the electric utility's standby charges for DG projects. The monthly contract demand and as-used demand charges required for these DG projects act as an additional monthly fixed cost on top of the one-time capital cost of the project, which must be overcome by the energy savings to achieve the desired payback. In addition, if the customer exceeds their contract demand in any month, the penalties associated with this overrun can be potentially large enough to wipe out all the annual energy savings from the project for that year. Finally, the most recent barrier to DG projects has been the shift in the power industry from an "all hours" or "on-peak/off-peak" commodity and delivery rate structure to a

1 mandatory real time commodity pricing for their larger
2 commercial/industrial customers. The new real time pricing has
3 resulted in a market where the cost of power changes on an hourly
4 basis, instead of the old model where the commodity cost was the
5 same for the entire month, or only varied at night or on the weekend.
6 This new 24/7 pricing structure has drastically complicated the
7 analysis of DG projects, making it much more difficult to estimate a
8 DG project's economics. It has also made it much more difficult to
9 properly design and operate a DG system, given the changing hourly
10 power prices, especially in conjunction with matching the associated
11 thermal heat recovery output of the DG project with the customer's
12 thermal needs on an hourly basis. All of these factors have combined
13 to put a damper on the growth of DG in our service territory. Most of
14 the 19 DG installations mentioned earlier were installed in the 1990's
15 and early 2000's, before some of the above barriers became more of
16 an impediment. Customers are currently still very interested in DG,
17 but they are very aware and wary of the obstacles they face.
18 Q. What is Distribution doing to address these barriers?
19 A. Distribution has no control over most of the barriers mentioned
20 above – thermal load profiles, electric utility standby charges and

1 real time power prices. However, we have attempted to address the
2 barrier of the high capital cost of DG projects. On June 21, 2002,
3 Distribution filed a proposal with the Commission to allow the
4 Company to promote the development of DG in its New York service
5 territory by permitting the Company to buy down (reduce) the initial
6 cost of installing DG equipment at customer facilities. On March 20,
7 2003, the Commission issued an Order in Case 02-G-0858 ("Order"),
8 approving Distribution's DG Pilot Program. Distribution's DG Pilot
9 Program is designed to improve a customer's project economics by
10 reducing the project payback through a one-time payment or buy
11 down toward the cost of the DG installation. The Company recovers
12 the customer buy down through future incremental transportation or
13 sales service charges. This assures that buy down costs will be
14 borne by the DG customers on a project-by-project basis. In
15 accordance with the Order, the Company has implemented this
16 program on a pilot basis over a three-year period. The program has
17 an annual buy down cap of $1,000,000 per year, for a total program
18 cap of $3,000,000. The typical buy down per customer is in the
19 range of $50,000 to $150,000. All participating customers must sign
20 a performance contract with a term of up to six years and may be

required to provide security to cover the Company's buy down amount.

Q. How does the DG Pilot Program benefit the Company's ratepayers and its customers?

A. Promoting DG is beneficial to the Company's ratepayers given the high, year-round natural gas load factors and incremental volumes generated by DG customers. These increased loads help Distribution spread out system fixed costs over larger throughput and improve utilization of the system during off-peak, shoulder and summer months. For commercial and industrial customers, DG allows them to reduce their energy costs, helping them be more competitive. DG is consistent with the state's ongoing efforts to reduce the cost of doing business in New York to maintain and attract employers.

Q. How many customers have participated in the DG Pilot Program?

A. To date, six (6) customers have signed a contract and received an incentive through this program. This has resulted in an annual increased usage of 282,348 Mcf on Distribution's system. The total incentive amount given to these 6 customers was $653,000.

Q. How does Distribution currently introduce and deploy information on gas technologies and energy efficiency to its customers?

A. For the approximately 400 large commercial/industrial customers greater than 12,000 Mcf, Distribution uses several sources to convey information on the above topics. *Gas Technology* is a magazine that is mailed 3 times a year to these customers, and features articles on existing and new HVAC and process technologies, as well as DG, engine drive technologies and waste treatment. Distribution has also developed a series of technology information profiles for many of the gas technologies mentioned above, along with case histories highlighting some of the successful installations in our service territory. They are mailed or handed out in person to these customers to help introduce them to these technologies. They are also posted on our website for customers to look at and download/print at their computer. For our residential and small non-residential customers using less than 12,000 Mcf annually, Distribution has developed a broad umbrella trade ally program, "The Energy Partnership", with the goal of building and maintaining preference for natural gas among key influencers such as appliance dealers, heating/plumbing contractors, builders, architects and

1 engineers. This program exists because of the strong influence
2 these trade allies have on the use of natural gas and gas equipment
3 by Distribution's residential and small non-residential customers in
4 the replacement/retrofit and new construction market. The program
5 offers Cooperative Advertising to reinforce the benefits of natural gas
6 such as efficiency, economy and environmental. Training is also a
7 typical component of the program with an emphasis on safety and
8 technical issues (equipment venting, building codes and standards
9 and new technologies).

10 **B. Research, Development & Demonstration (RD&D) Program**

11 Q. Does Distribution have an RD&D program to assist in advancing new
12 technology to the market place?

13 A. Yes, Distribution has conducted an RD&D Program dating back to
14 the mid 1980's.

15 Q. What are the goals and objectives of the RD&D Program?

16 A. The goals of the RD&D program are to identify emerging natural gas
17 technologies of benefit to Distribution and its customers, fund
18 developments through co-funded gas industry RD&D organizations
19 and manufacturers, demonstrate appropriate technologies in our
20 service territory and disseminate information to customers who could

benefit from the technologies. For technology demonstration projects, Distribution seeks to have the technologies located at host sites with vested interests in the success of the technologies.

Distribution does not internally conduct research and development. It does provide funding for external R&D initiatives in concert with other gas industry, manufacturing, energy/environmental authorities, and other participants.

The primary purpose of the RD&D program is the identification, development, introduction and demonstration of new technologies, equipment and processes which feature increased efficiency and improved performance in the residential, commercial and industrial end use market segments, as well as in the distribution operations area. The main emphasis of the RD&D program is on:

- Providing customers with a greater selection of energy-efficient, low emissions gas technologies;
- Remain competitive with other energy technologies to contribute to the positive environmental attributes of natural gas;
- Reduction of fixed operating costs;

- Improved gas load factors for greater seasonal utilization of gas facilities;
- Increased safety and efficiency in delivering natural gas; and
- Increased customer benefits.

Q. What types of programs does the RD&D Program support?

A. Distribution's RD&D program in New York State consists of the **Traditional RD&D Program** funded through base rates and the **Millennium Funds RD&D Program** which uses a separate rate surcharge collected from New York ratepayers.

Q. Please describe the programs funded through the Traditional RD&D Program.

A. The Traditional Program addresses technology segments for Residential, Commercial and Industrial End-Use markets, and for Company Operations technologies.

Internal RD&D – The Internal RD&D Program addresses technologies nearing commercialization and consists of conducting Technology Demonstration projects, Technology Assessments, and Technology Transfer. Demonstration projects are initiated, implemented, and managed by Distribution personnel. Technologies

demonstrated include new/emerging natural gas equipment, or other technologies not in significant use in our service territory.

The Internal RD&D program is divided into the following 3 areas:

- **End Use** – This area consists of projects in the residential, commercial and industrial market segments featuring new and emerging technologies.
- **Operations** – This area consists of projects pertaining to Distribution's gas infrastructure including reliability, productivity, safety and the environment.
- **Other** – This area consists of funding set aside to cover Technology Assessment, Technology Transfer and General Administrative expenses of the RD&D program.

External RD&D – The internal activities are supplemented by external research. This consists of projects and programs funded under the Traditional RD&D Program. These external projects are managed by professional organizations experienced in RD&D and in the commercialization of natural gas/energy technologies.

The External RD&D program supports funding for the following two organizations:

- **New York State Energy Research & Development Authority ("NYSERDA")** - Distribution is a source of funding to NYSERDA through a mandatory assessment. The NYSERDA assessment is the largest single component of the Distribution Traditional RD&D Program.
- **Northeast Gas Association Research Committee ("NYSEARCH")** – Distribution funds end-use and/or operations projects on a voluntary basis by participating in the Research Committee. Distribution selectively initiates or contributes to technology development projects managed by NYSEARCH and receives project reports and other information. NYSEARCH leverages the resources of its membership by contracting for applied research by other qualified organizations.

Q. Please describe the programs funded through the Millennium Funds.

A. The Millennium Funds Program at Distribution was established during the transition from the mandatory Gas Research Institute ("GRI") Program under FERC jurisdiction, which began in 2000 (Case No. 99-G-1369). As GRI funding was reduced to zero over a five-year period, the Commission allowed for the collection up to the

difference of the previous New York share of the federal assessments to fund RD&D in New York State. The initial order essentially limited expenditures to Company Operations technologies, with opportunities to petition for special consideration of natural gas appliance or supply/storage research. A subsequent Order (Case No. 04-G-1047, Joint Proposal, July 22, 2005) allowed funding for natural gas appliance applications research and approved end-use energy efficiency programs.

Millennium Funding is provided to NYSEARCH on a project-by-project basis to arrange for research on behalf of the New York State gas industry. NYSEARCH efforts allow for the funding to be leveraged with other participants, which further allows the industry to undertake new technology development Distribution could not individually undertake alone.

Millennium Funds are also used to support the following programs offered through the Gas Technology Institute:

- **Utilization Technology Development** ("UTD") – The UTD is involved in the research and development of natural gas utilization including residential and commercial appliances, industrial process, distributed generation and natural gas

vehicles. The program strives to meet critical demands by the United States for energy by providing efficient, safe, economical and environmentally acceptable uses of natural gas to the benefit of the public.

- **Emerging Technology Program** ("ETP") – Distribution funding for this program is included within UTD. ETP is a new initiative by GTI, created in 2012, to address issues in better moving technologies from development to commercialization. In spite of many attractive technology developments after gas industry RD&D restructuring, much of the former effective infrastructure and staffing in moving those technologies to market no longer exist. ETP is an effort to re-establish that necessary function.
- **Operations Technology Development** ("OTD") - The OTD develops, tests, and implements new technologies to provide solutions to a wide range of issues relating to gas operations and its infrastructure. It is designed to provide new tools, equipment, software, processes, or procedures that will enhance safety, increase operating efficiency, reduce operating costs, and help maintain system reliability and

integrity. The scope of the program includes mid- to near-term developments.

- **Sustaining Membership Program** ("SMP") – Distribution funding for this program is included within OTD. The SMP strives to develop new and innovative technology concepts that will address current needs and will reduce the cost of transmission, distribution and environmental operations for member companies. The SMP addresses mid- to longer-term developments.

Q. How does Distribution manage the RD&D Program?

A. The Energy Services Department is responsible for the overall administration of Distribution's RD&D program, managing the end-use demonstration projects of the Traditional Internal program, and managing the end-use RD&D activities within the Millennium Funds Program. The Mechanical Department of Distribution's Operations Division is responsible for managing the company's operations projects within the Traditional Internal program, and within the Millennium Funds Program.

The Energy Services Department and the Mechanical Department use existing department personnel to manage RD&D projects, but

occasionally use personnel on loan from other departments as project managers, as needed. From time to time, Distribution may also assign personnel to an external project of NYSEARCH or GTI where some special interest and expertise exists within the company.

Q. How are RD&D projects identified and selected for funding?

A. Projects may originate from various internal and external sources and may consist of domestic or international technologies. Upon identifying a technology worthy of supporting, its potential benefits are determined, as well as determining what we hope to achieve with a project. The impact of technologies can vary widely depending upon differing regional needs. Information is gathered and presented for approvals. Before funds and other resources are committed, approvals are received from Senior Management with permission to charge expenses. Each approved project is planned to include scope, budget, schedule and goals. At project completion, the results are gathered, reported and filed.

Q. What were the annual expenses for the RD&D program in calendar 2015?

A. For calendar year 2015, expenses between the Internal, External, and Millennium Funds programs are shown below:

Internal RD&D		
188002 – Commercial End Use	$ 30,330	
188005 – Operations	$ 38,840	
188007 – Technology Transfer	$ 19,740	
188008 – Technology Assessment	$ 34,109	
188009 – General Administration	$ 34,121	
Internal RD&D Total		**$ 157,140**
External RD&D		
188003 – NYSERDA	$ 833,221	
188004 – NYSEARCH	$ 63,767	
External RD&D Total		**$ 896,988**
Millennium Funds RD&D (188050)		
GTI – 2015 OTD Dues	$ 315,500	
GTI – 2015 UTD Dues	$ 157,700	
GTI – 2016 OTD Dues	$ 315,500	
NYSEARCH	$ 244,564	
American Gas Foundation	$ 10,000	
Millennium Funds RD&D (188050) Total		**$ 1,043,264**
Grand Total		**$ 2,097,392**

Q. What is Distribution's forecast for future expenses in the RD&D Program?

A. Please see Distribution's Three-Year RD&D Forecast which was recently filed with the PSC on March 31, 2016.

C. Economic Development Program and Area Development Program

Q. Please provide a procedural background describing the Commission's ordered authorization for the Area Development Program ("ADP").

A. On June 2, 2006, as part of Case 04-G-1047, the Commission issued its Order approving the ADP. The ADP was established to provide grants to community based organizations or local development authorities, or directly to project applicants, for specific economic development projects in order to expand economic opportunities in Distribution's service territory.

Q. What is Energy Services' role in the ADP?

A. The Energy Services Department is responsible for general administration and implementation of the ADP. These responsibilities include outreach, website administration, application assistance, application evaluation, review coordination, tracking and Commission reporting.

Q. How are the ADP grants awarded?

A. The ADP committee comprises representatives from the following departments: Rates and Regulatory Affairs, Corporate

1 Communications, Government Affairs, Energy Services and
2 Corporate Executives. The committee meets as needed, depending
3 upon the number of applications in the queue. Each project is
4 evaluated according to the criteria in Case 04-G-1047.
5 Q. Does the committee consider other factors when awarding grants?
6 A. Yes.
7 Q. What types of other factors are considered?
8 A. Other considerations include the financial need of the applicant, the
9 benefit to, or impact on, Distribution's ratepayers and the level of
10 support or partnership with other cooperative agencies.
11 Q. How does the committee evaluate the criteria?
12 A. The committee determines the award based upon on how well the
13 project meets some or all of the criteria using a high-medium-low
14 scoring method.
15 Q. How are the funds distributed?
16 A. The ADP funds are distributed contingent upon meeting the
17 requirements established during the evaluation process. Each grant
18 has differing circumstances on how and when funds are distributed.
19 Once the requirements have been met, a request is made to release

1 funds in the form of a credit to the applicant's internal invoice or a
2 check is issued.
3 Q. How are these funds tracked?
4 A. The funds are tracked through accounting transactions recorded by
5 the Rates and Regulatory Affairs department.
6 Q. Do you track the incremental gas usage associated with these
7 projects?
8 A. The ADP grant recipients' gas usage is tracked periodically. Energy
9 Services records the estimated usage in the application and
10 compares this to actual usage.
11 Q. Does Distribution verify the job and investment estimates?
12 A. The Company does not independently assess applicants' jobs and
13 investment estimates. Furthermore, the ADP grant, in most
14 instances, is part of a portfolio of economic development benefits
15 provided by multiple agencies and providers. However, Energy
16 Services periodically contacts the recipients to discuss their projects.
17 We attempt to verify their new and/or retained employee estimates
18 versus current employment levels, conduct site visits to verify the
19 project's completion and maintain relationships established during
20 the application process.

1 Q. How do you promote the ADP?

2 A. The ADP is promoted using various types of outreach methods. We
3 send out periodic news releases detailing the program and its
4 objectives and have taken print ads in numerous local publications.
5 We have created an ADP brochure explaining the program criteria
6 and how to apply for funding. The brochure also describes success
7 stories. We have continued to maintain our web page explaining the
8 program on the company web site under the "For Business" section.
9 Finally, the Energy Services account managers have continued to
10 promote the program by conducting small-scale presentations to
11 customers and various economic development agencies. The
12 economic development agencies package these incentives to
13 supplement their attraction and expansion efforts. Once ADP
14 applicants are identified, the respective Energy Services account
15 manager guides the customer through the grant process.

16 Q. How many grants have been awarded since the program inception?

17 A. Please refer to the ADP report dated March 31, 2016 and filed in
18 Case 13-G-0136.

19 Q. Do you offer any other economic development tools?

A. Yes. Distribution offers discounted rates to eligible commercial and industrial customers within our service territory. Distribution has two discount rates available. The two discount rates are the Business Development Rate and Excelsior Jobs Program Rate.

Q. Can you describe the Business Development Rate ("BDR")?

A. The BDR is a transportation rate discount available to businesses with a qualifying SIC code, qualifying facility and that meet incremental usage requirements. The discounts will apply for a five year period assuming the yearly incremental usage requirements are met.

Q. What is a qualifying facility?

A. A qualifying facility is a newly constructed facility, an expansion of an existing facility, or an existing facility that has been purchased or leased and has been vacant for at least six months.

Q. What are the incremental usage requirements?

A. The gas consumed by a new customer at a qualifying facility shall be eligible if the gas consumption is in excess of 2,400 Mcf per year. The incremental gas consumption for an existing customer at a qualifying facility must increase by 20% of the applicant's prior year normalized load or 2,400 Mcf per year, whichever is less.

Q. Are the requirements for the Excelsior Jobs Program Rate the same?

A. No. Excelsior Jobs Program customers require an annual certification of eligibility as defined in Article 17 of the Economic Development Law. A qualifying facility is the same as the BDR with one additional consideration. The facility needs to be located within an area that has been certified under the New York State Economic Development Zones Act as an economic development zone and the customer is certified by New York State and maintains their annual certification mentioned above. The incremental usage requirement is also different. The gas consumed by a new customer at a qualifying facility shall be eligible if the gas consumption is in excess of 1,200 Mcf per year. The incremental gas consumption for an existing customer at a qualifying facility must increase by 20% of the applicant's prior year normalized load or 1,200 Mcf per year, whichever is less. However, the incremental usage will not qualify unless the incremental usage is at least 600 Mcf per year. Lastly, the term of the discount is 10 years instead of the BDR's 5 year term.

Q. Is there an application process?

A. Yes. Distribution must receive the application for Business Development Rate or Excelsior Jobs Program Rate at least thirty days prior to the start-up date of the new or expanded facility.

Q. How is the discount rate applied?

A. The discount rate is applied on a volumetric rate class category per Ccf. The discount rate will decline over a period of time. Depending on which discount rate, the declining period varies.

D. PRIME-WNY Pilot Program

Q. Please provide background describing the Commission's ordered authorizations for the Partnership to Revitalize the Industrial Manufacturing Economy of Western New York ("PRIME-WNY") program.

A. On May 15, 2015, as part of Case 14-G-0551, the Commission issued an Order Authorizing the Partnership to Revitalize the Industrial Manufacturing Economy of Western New York (PRIME-WNY)

Q. Please describe the PRIME-WNY program.

A. Distribution utilizes shareholder funds to incent large commercial and industrial customers to install incremental natural gas fired equipment at their existing facilities by buying down the customer's

1 investment in system improvements, associated piping, and/or
2 customer equipment.
3 Q. How does this benefit a customer?
4 A. The benefit to the customer is that it pays back the buydown amount
5 with the delivery rates associated with the incremental load. By
6 comparison, a non-participant seeking equipment funding would pay
7 the delivery rates for the incremental load and a loan payment for the
8 equipment costs.
9 Q. How does this program benefit all ratepayers?
10 A. Distribution is allowed to retain $0.10 per Mcf charge contribution to
11 overall system costs which is a benefit for all ratepayers. After the
12 buydown is repaid, the increased gas throughput allows fixed utility
13 costs to be spread over a greater usage volume, which results in
14 lower unit costs benefitting all ratepayers.
15 Q. How does this program benefit the shareholder?
16 A. The shareholders would be compensated through the retention of
17 the incremental revenues derived from the customer's incremental
18 load until the buydown is fully recovered, with interest.
19 Q. Does the customer need to sign a contractual agreement?

1 A. Yes. In order to ensure full recovery of shareholder funds,
2 Distribution enters into a contractual agreement with the customer.
3 Q. How many years would the performance agreement be for?
4 A. The contractual agreement can be for a period of one year up to
5 seven years. As a result of the term chosen, it will have a direct
6 affect on the buydown amount.
7 Q. Do you require security on these contractual agreements?
8 A. Yes. Distribution requires a Letter of Credit or a cash security
9 deposit in the amount of the investment.
10 Q. Does Distribution have any customers using the PRIME WNY?
11 A. Yes. To date, Distribution has a contractual agreement with one
12 customer.
13 **E. Reforming the Energy Vision Activities**
14 Q. On December 12, 2014, as part of Case 14-M-0101, the Commission
15 issued its Order on the Proceeding on Motion of the Commission in
16 Regard to Reforming the Energy Vision ("REV"), which aims to align
17 electric utility practices and the Commission's regulatory paradigm
18 with technological advances in information management and power
19 generation and distribution. How does Distribution currently
20 participate in advancing the REV Proceeding policy objectives?

A. Distribution has been involved in three microgrid projects, all of which are active participants in NYSERDA's New York Prize program. Distribution has issued a letter of support for the BNMC project, to be submitted with their NY Prize application. This project was selected to receive an award of $100,000 to fund a feasibility study as part of NY Prize. Distribution is an active participant in "Energize BNMC" project, and the Company is funding a thermal load study as part of Distribution's Research and Development Program, to assess the feasibility of a natural gas CHP technology application. Distribution has also issued a letter of support for the Village of Westfield project, to be submitted with their NY Prize application. This project was selected to receive an award of $100,000 to fund a feasibility study as part of NY Prize. Finally, Distribution has issued a letter of support for the Village of Arcade project, to be submitted with their NY Prize application. This project was selected to receive an award of $100,000 to fund a feasibility study as part of NY Prize.

Q. Can you describe in more detail your involvement with the BNMC project?

A. Distribution's primary contribution to the BNMC team has been

support of the thermal loads study. This study has been completed and the final report shared with the BNMC project team for incorporation into the stage 2 submission. The preliminary analysis of CHP possibilities was also presented to two of the BNMC member organizations, at separate, in person meetings. BNMC wanted to have these meetings at this early stage to ensure that the member institutions are kept involved throughout the process. Both organizations were receptive and interested in the project in general, but it is clear that the long payback periods and questions related to system ownership and operation will be significant hurdles to overcome.

F. Telemetering

Q. According to Distribution's Tariff No. 8, on Leaf 217, certain customers are required to have telemetering installed. What customers are required to have telemetering equipment installed?

A. Customers who use 55,000 Mcf per year or greater are required to install telemetering equipment. Customers who choose Daily Metered Transportation (DMT) service are also required to have telemetering equipment installed.

Q. What happens to a customer using 55,000 Mcf per year who drops below that threshold in the future?

A. That customer is allowed to opt out of maintaining their telemetering equipment.

Q. Why are they allowed to opt out?

A. These customers did not volunteer to install the telemetering equipment, they were mandated.

Q. What happens to a DMT customer using less than 55,000 Mcf per year, who migrates back to Monthly Metered Transportation ("MMT")?

A. Based on the customer volunteering for DMT service, they are required to maintain the telemetering equipment for the existence of their account.

Q. Would you like to see these requirements changed in the future?

A. Yes. Distribution is requesting to allow a customer the option of removing their telemetering equipment if they use less than 55,000 Mcf per year, and they migrated back from DMT service to MMT service.

Section 5 – Energy Efficiency and Growth Activities, Small Volume Customers

Q. Please provide a procedural background describing the Commission's ordered authorizations for the Company's energy efficiency program.

A. On September 20, 2007, as part of Case 07-G-0141, the Commission issued its Order Adopting Conservation Incentive Program, which established CIP as Distribution's energy efficiency program and authorized the program to run from 2007 to 2009. CIP is unique, in that the program preceded the development of Energy Efficiency Portfolio Standard ("EEPS") programs established for other natural gas utilities in New York State. On October 19, 2009, the Commission issued its Order Approving the Continuation of National Fuel Gas Distribution Corporation's Incentive Program with Modifications, reauthorizing CIP to continue during 2010. On November 22, 2010, the Commission issued its Order Approving the Continuation of National Fuel Gas Distribution Corporation's Conservation Incentive Program with Modifications, reauthorizing CIP to continue during 2011. On October 25, 2011, the Commission issued its Order Authorizing Efficiency Programs, Revising Incentive

Mechanism, and Establishing a Surcharge Schedule, which incorporated CIP within the EEPS portfolio of statewide energy efficiency programming and reauthorized the program to continue from 2012 to 2015. On February 19, 2013, the Commission issued its Order Approving in Part and Denying in Part National Fuel Gas Distribution Corporation's Petition to Modify Certain Energy Efficiency Programs, which authorized the Company to reallocate budgets and savings targets between its Residential Rebate Program and its Low Income Usage Reduction Program ("LIURP"). On June 19, 2015, the Commission issued its Order Authorizing Utility-Administered Gas Energy Efficiency Portfolios, which authorized budgets and targets for CIP to continue during 2016. Finally, on January 22, 2016, the Commission issued its Order Authorizing Utility-Administered Energy Efficiency Portfolio Budgets and Targets for 2016 – 2018, which: (1) reaffirmed budgets and targets for CIP to continue during 2016, and (2) established budgets and targets for CIP to continue during 2017 and 2018.

A. Conservation Incentive Program

Q. Please list the programs included in Distribution's CIP.

A. CIP includes the following programs: (1) Residential Rebate

Program, (2) Non-Residential Rebate Program ("NRCIP"), and (3) LIURP. In addition, each of the programs is supported with Outreach and Education ("O&E") and Evaluation, Measurement, and Verification ("EM&V") initiatives.

Q. Please describe the Residential Rebate Program and the program's offering to customers.

A. The Residential Rebate Program is an equipment replacement program, modeled after a Vermont Gas Systems program, which was cited by the American Council for an Energy-Efficient Economy ("ACEEE"), as one of the nation's exemplary natural gas energy efficiency programs. Distribution's program offers equipment replacement rebate incentives for single-family and multi-family residential dwellings, to encourage them to install high efficiency space heating and water heating appliances. These types of appliances are by far the largest two users of natural gas in residential buildings, and are therefore most likely to show the largest savings to customers when they upgrade their appliances. Distribution sets minimum efficiency levels for each appliance type based on federal Energy Star and New York State Energy Smart guidelines. The goal of the Residential Rebate Program is to

encourage the installation of high efficiency appliances or equipment by customers.

Q. What are the Residential Rebate Program's currently effective minimum efficiencies and rebate dollar amounts?

A. The target market for the Residential Rebate Program is all residential customers within Distribution's New York service territory. All residential customers are eligible to participate in the Residential Rebate Program. Rebates are available for existing single-family dwellings, multi-family dwellings, condominiums and mobile dwellings. The currently effective minimum efficiencies (measured in annual fuel utilization efficiency ("AFUE") or energy factor ("EF") where applicable) and rebate dollar amounts are as follows:

- Hot Air Furnace – 90% AFUE; $325
- Hot Air Furnace With Electronically Commutated Motor ("ECM") – 90% AFUE; $400
- Hot Water Boiler – 90% AFUE; $700
- Steam Boiler – 82% AFUE; $200
- Storage Tank Water Heater – 0.67 EF; $75
- Tankless Water Heater – 0.82 EF; $375
- Indirect Water Heater – N/A; $275

- Programmable Thermostat – N/A; $25, and
- Wi-Fi Thermostat – N/A; $75

These incentives will help offset a portion of the incremental cost of purchasing high efficiency equipment in place of standard efficiency equipment. In addition, these incentives will help customers that are switching fuel sources to natural gas from another fuel (e.g., oil, propane or electricity).

Q. What are the results of the Residential Rebate Program, with respect to number of customer participants and the dollar amount of rebates?

A. Since the inception of CIP in September 2007, and as of December 31, 2015, Distribution has processed more than 108,000 rebates. This corresponds to approximately $20.6 million of incentives for Distribution's customers. Consistent with Commission policy objectives, the Residential Rebate Program produces energy savings for customers, the value of which exceed program expenditures. For more details on the Residential Rebate Program, please refer to Distribution's Energy Efficiency Transition Implementation Plan ("ETIP") for the 2016 to 2018 period, which was filed on April 1, 2016 in Case 15-M-0252.

Q. Please describe NRCIP and the program's offering to customers.

A. NRCIP is a space, water and process heating equipment replacement program that offers fixed ("prequalified") and customized ("performance-based") rebate incentives to small, non-residential customers using less than 12,000 Mcf of natural gas per year. Like the Residential Rebate Program, NRCIP was modeled after a Vermont Gas Systems program that was cited by the ACEEE as an exemplary natural gas energy efficiency program. The goal of NRCIP is to provide cost effective incentives to small non-residential customers utilizing natural gas efficiently in their business operations. Fixed rebates on pre-qualified equipment are available to customers and are designed to be quick and easy, utilizing a straightforward application process. For fixed rebates, Distribution sets minimum efficiency levels for each appliance type based on federal Energy Star and New York State Energy Smart guidelines. Customized rebates are also available to customers on a case-by-case basis, at a level of $15 per Mcf multiplied by an estimate of natural gas energy savings to be achieved from the completion of a project. Examples of customized rebates include, but are not limited to, energy efficient: process heating equipment, furnaces, boilers,

water heaters, steam/hot water distribution piping insulation, boiler control systems, flue gas economizers, thermostats or heat recovery systems. All energy efficiency projects resulting in natural gas savings will be considered for a customized rebate. Technical engineering analyses are performed in order to validate and confirm energy savings. It should be noted that the commercial/industrial housing stock in the Company's service territory is much more heterogeneous in nature than the more homogenous mix of residential households. Due to the wide variety of commercial/industrial facilities in Distribution's service territory with respect to building size, building envelope, equipment and operating hours, it is not practical to set one fixed rebate amount for such a wide variety of applications. However, for very small customers (e.g., retail stores, restaurants, office buildings, etc.) that are installing standard residential size space and water heating equipment, a standard fixed rebate schedule is much more practical. As a result, both fixed and customized rebates continued to be offered as part of NRCIP.

Q. What are NRCIP's currently effective minimum efficiencies and rebate dollar amounts?

A. The target market for NRCIP is all non-residential customers within Distribution's New York service territory that utilize less than 12,000 Mcf of natural gas per year. All installations must be completed by a licensed contractor. A full listing of the currently effective minimum efficiencies and rebate dollar amounts can be found in Distribution's ETIP for the 2016 to 2018 period, which was filed on April 1, 2016 in Case 15-M-0252.

Q. What are the results of NRCIP, with respect to number of customer participants and the dollar amount of rebates?

A. Since the inception of CIP in September 2007, and as of December 31, 2015, Distribution has processed more than 1,700 rebates. This corresponds to approximately $2.3 million of incentives for Distribution's customers. Consistent with Commission policy objectives, NRCIP produces energy savings for customers, the value of which exceed program expenditures. For more details on NRCIP, please refer to Distribution's ETIP for the 2016 to 2018 period, which was filed on April 1, 2016 in Case 15-M-0252.

Q. Please describe LIURP and the program's offering to customers.

A. LIURP is a weatherization program designed specifically for low income customers. Participants receive a heating system check, an

energy audit, weatherization measures and consumer education. The program design is consistent with, and is being administered in conjunction with the NYSERDA EmPower New York program. The main goal of LIURP is to conserve energy, reduce residential energy bills, and improve the health, safety, and comfort levels for participating households. A secondary goal includes reducing the incidence and risk of delinquencies and the costs associated with uncollectible amounts, late payment collections, and termination of service expenses.

Q. Please describe Distribution's health and safety furnace replacement initiative.

A. Beginning January 1, 2016, as part of LIURP, Distribution has earmarked $250,000 of incentives and services funding per year for a low income health and safety furnace replacement initiative. This initiative is modeled after the Home Energy Assistance Program ("HEAP") Heating Equipment Repair and Replacement Program, which historically exhausts funding during the middle of the HEAP season. To the extent that HEAP eligible customers contact Distribution directly about old and inefficient heating equipment, malfunctioning heating equipment, or potential safety concerns,

especially during the winter heating season, the Company would be able to have a contractor immediately install a high efficiency furnace and programmable thermostat at no cost to the customer. This furnace replacement initiative: (1) augments existing limited health and safety protocols currently in place as part of LIURP and EmPower, (2) supports the primary goal of LIURP, (3) helps prevent emergency situations for customers due to an underfunded portion of HEAP programming or a general lack of available options, and (4) produces energy savings by replacing legacy heating equipment with high efficiency heating equipment that low income customers may not otherwise be able to afford.

Q. What are the results of LIURP, with respect to number of customer participants and the dollar amount of weatherization services?

A. Since the inception of CIP in September 2007, and as of December 31, 2015, Distribution has completed more than 7,100 weatherization jobs. This corresponds to approximately $26.6 million of incentives for Distribution's customers. Consistent with Commission policy objectives, LIURP produces energy savings for customers, the value of which exceed program expenditures. For more details on LIURP, please refer to Distribution's ETIP for the 2016 to 2018 period, which

was filed on April 1, 2016 in Case 15-M-0252. With respect to the results of LIURP, it is also important to note a key finding from Distribution and NYSERDA's 2014 joint evaluation work: 68% of all of New York State's low income weatherization work completed during the evaluation period occurred within the Company's service territory. Distribution's LIURP has: fostered a successful collaboration with NYSERDA, achieved greater energy efficiency penetration levels, and resulted in an even distribution of work amongst multiple contractors.

Q. Where can additional detailed information about Distribution's CIP be found?

A. Please refer to Distribution's ETIP for the 2016 to 2018 period, which was filed on April 1, 2016 in Case 15-M-0252. This document provides an overview of Distribution's CIP, as well as detailed information for each program within CIP (i.e., Residential Rebate Program, NRCIP and LIURP). Distribution's ETIP includes the following detailed information:

- Portfolio Budgets and Targets
- Forecasted Portfolio Expenditures and Achievements
- Portfolio Funding Requirements

- Portfolio Benefit Cost Analysis
- Program Design and Administration
- Program Delivery Methods
- Program Target Markets and Eligibility
- Program Quality Assurance / Quality Control
- Program Budgets and Targets
- Program Participation Rates and Savings Derivation
- Program Benefit Cost Analysis, and
- Descriptions of EM&V Initiatives

Q. Is Distribution proposing any changes to CIP as part of this rate proceeding?

A. No, it is not necessary to make any modifications in this proceeding, as described herein. On February 26, 2015, in Case 14-M-0101, the Commission issued an Order Adopting Regulatory Policy Framework and Implementation Plan. This Order set forth an annual process whereby electric utilities would propose post-2016 energy efficiency budgets and targets for Commission approval ("Budget and Metrics Plan" or "Budget and Metrics Plans"). As part of that annual process, the Order directed the completion of ETIP filings to address the energy efficiency efforts associated with proposed budgets and

targets. On May 1, 2015, in Case 15-M-0252, Department of Public Service Staff (in collaboration with the E2 Working Group), filed an ETIP Guidance Document. This Guidance Document established common specifications and minimum requirements that each utility must follow in the development of ETIP filings to inform the annual approval of utility Budget and Metrics Plans. On June 19, 2015, in Case 15-M-0252, the Commission issued an Order Authorizing Utility-Administered Gas Energy Efficiency Portfolios for Implementation Beginning January 1, 2016. In this Order, the Commission determined that the administration of gas energy efficiency programs should align with that of electric efficiency programs, and therefore required gas utilities to implement their energy efficiency programs under the same framework as that established for electric programs on February 26, 2015. Based on this procedural history and the Commission's June 19, 2015 determination, the appropriate forum for Distribution to propose changes to CIP is the annual Budget and Metrics Plan reauthorization process. In summary, Distribution is not proposing any changes to CIP as part of this rate proceeding.

Q. Did the Company experience loss of throughput by implementing

1 CIP?

2 A. Yes. Distribution has experienced load loss from customer
3 conservation measures including the efficiencies described in above.
4 Distribution's CIP has by its very design resulted in reduced
5 consumption of natural gas, and therefore reduced throughput.

6 **B. Gas Network Enhancement Program**

7 Q. Please provide background describing the Commission's ordered
8 authorization for the Gas Network Enhancement Plan ("GNEP").

9 A. On May 8, 2014, the Commission approved the terms of a Joint
10 Proposal establishing rates and services for the Company in Case
11 13-G-0136. The Joint Proposal included a provision requiring the
12 Company to submit a plan, bearing specific features and services
13 sought by the parties, for the reasonable extension of gas service to
14 unserved applications and communities. The Company filed its
15 GNEP on August 6, 2014 and notified parties of a collaborative
16 scheduled to further develop the GNEP's terms and conditions.
17 The first collaborative meeting regarding the GNEP was held on
18 September 4, 2014 in Niagara Falls, NY and a follow up meeting
19 was conducted on September 23, 2014 in Albany, NY. On October
20 8, 2014, the Company submitted a compliance filing with the results

of these collaborative meetings in which the GNEP's terms and conditions were further developed. The October compliance report detailed the participants' belief that it would be useful to implement some of the proposals included in the GNEP immediately so that benefits can be realized by homes and businesses within the Company's service territory, specifically in time for the heating season. The report detailed two programs that are being implemented as a result of the two previous collaborative meetings: (1) a Gas Expansion Pilot Program; and (2) a program to provide financial support to low income customers to enable their full participation in gas expansion. It also stated that funding will be provided to enhance the Company's Geographic Information System ("GIS") to enable the Company to better identify areas for expansion and conversion. The programs being implemented are in compliance with the Rate Order and the GNEP, and no tariff changes were required. It is important to note that work completed as part of Distribution's GNEP helps to offset housing demolitions. The Company estimates that approximately 346 demolitions occur annually.

Q. What are the target market(s) for Distribution's GNEP?

1 A. Target markets include:

2 1) non-customers that are currently more than 100 feet beyond the
3 end of Distribution's gas mainline infrastructure;

4 2) non-customers that are less than 100 feet from Distribution's gas
5 mainline infrastructure (commonly referred to as "SKIPS");

6 3) customers that have a gas service line/meter and a gas account,
7 but are not using natural gas for space heating; and

8 4) low income customers who may fall into any of the above three
9 categories.

10 Q. What are the economics associated with heating a medium sized
11 home (1,500 square feet) with natural gas compared to fuel oil,
12 propane and electric resistance heat?

13 A. For a 12 month period ending September 2015, Distribution
14 estimated that the cost to heat the natural gas home was $797.
15 Estimated annual heating costs for fuel oil, propane and electric
16 resistance were $1,650, $2,000 and $3,220 respectively.

17 Q. What are some of the obstacles to converting to natural gas?

18 A. The cost to purchase and install natural gas heating, hot water and
19 other appliances can be substantial. For fuel oil customers, there is
20 the added expense and inconvenience of removing the oil tank,

following environmental regulations and having to install gas piping in the home. Electric resistance heating customers may need a complete forced air or hydronic heating system installed, at considerable expense, in addition to house gas piping. In addition, there is the up-front or monthly surcharge costs associated with installing new gas main for customers beyond the existing distribution system. Conservative estimated paybacks, for equipment replacement costs only, range from 2.7 to 7.5 years, depending on fuel type. For more details, see Appendix M of Distribution's Gas Network Enhancement Collaborative Annual Report, dated February 8, 2016 (Case 13-G-0136).

Using a series of focus groups and telephone interviews performed by Eric Mower and Associates in November of 2015, Distribution gained valuable insight into the current knowledge and perception of natural gas for heating among our non-customers and non-heating customers. Distribution also wanted to uncover motives for converting, as well as barriers to conversion. For more details, see pages 30-37 of the Distribution Gas Network Enhancement Collaborative presentation dated December 9, 2015 for results of that survey.

1 Q. How does the current mainline extension program ("MLEP") hinder
2 the process of a resident desiring to become a utility natural gas
3 customer?
4 A. Please see pages 8 and 9 under "Customer Conversion Costs" from
5 the Gas Network Enhancement Collaborative Annual Report, dated
6 February 8, 2016 and filed in Case 13-G-0136.
7 Q. What methods has Distribution utilized to identify prospects for
8 conversion to natural gas?
9 A. Distribution's New Services Department has provided input regarding
10 potential Gas Network Enhancement ("GNE") locations. In addition,
11 some GNE funding has been used to purchase real property tax map
12 data and enhance the company's GIS to enable the company to
13 better identify areas for expansion and conversion.
14 Q. What programs has Distribution developed to address the obstacles
15 for residents that want to convert?
16 A. The Company developed a Gas Network Enhancement Pilot
17 Program. This program streamlined the approach to expanding the
18 system by providing potential customers firm, long term main line
19 extension price quotes based on total cost of the expansion and a
20 reasonable estimate of the expected number of customers attaching

to the system over a ten year period. The prepayment or surcharge would be the same for all customers regardless of expected usage. Interested customers are given two firm price options; a one-time pre-payment or a monthly surcharge to be paid over ten years. Through this pilot program the Company will expand service throughout its service territory while testing the market impact on customer conversions to natural gas from providing firm, long term price quotes, as well as providing the Company with greater certainty for planning future system expansions.

The Company initially considered only areas that met specific requirements for pilot programs. The area needed to be of significant conversion potential where estimated monthly surcharges based on expected customer conversions can be $30 or less. Eligible areas for the pilot were also limited to only those with at least 100 potential customers. This ensured that the tests were meaningful and significant. Initial pilots were only conducted in areas that had demonstrated a long term interest in converting to natural gas. Number of applications previously received, frequency of inquiries, local community and government support for expediting the construction of facilities necessary to support the system expansion

are also used in determining if an area meets this program requirement. Based on these criteria two pilot programs were selected. One was located in Wilson, NY and the other in Richmond, NY.

Q. What are the Pilot Program results to date for the Wilson, NY and Richmond, NY areas?

A. **Wilson Pilot Program Results** - Overall, response from the residents was very positive and as of 12/8/15, 118 applications for service were received, and 69 residents, (49 percent) of the original estimate, have converted. Of those 69 conversions, 56 (81 percent) of these customers have chosen the upfront prepayment as opposed to the surcharge option. Applications for service have been growing steadily and the Company expects this trend to continue in the near future, especially as customers begin to see their neighbors' service being installed.

Richmond Pilot Program Results - Overall, response from the residents was very positive. Over 300 applications for service were received over the past few years and residents are eager to install service.

Throughout the winter of 2014/2015, the Company began to obtain rights of way ("ROW") agreements. Construction began in Summer 2015 and gas service was available to some residents in Fall 2015. Project completion is expected in Fall 2016. For a map of the project area, please see Appendix H of Distribution's Gas Network Enhancement Collaborative Annual Report, dated February 8, 2016 and filed in Case 13-G-0136.

Q. Does Distribution have plans for additional Network Enhancement Pilot Programs?

A. Yes. For a description of both Phase II and Phase III Gas Network Enhancement Projects, please see pages 18 and 19 of Distribution's Gas Network Enhancement Collaborative Annual Report, dated February 8, 2016 (Case 13-G-0136).

Q. Has Distribution developed a plan that would assist potential conversion customers with some of the substantial up-front costs they are presented with?

A. The Company has proposed a Gas Conversion Rebate Program which would add additional incentive dollars (for conversion customers only) to the existing CIP incentives. Please see pages 23 and 24 of the Gas Network Enhancement Collaborative Annual

Report, dated February 8, 2016 and filed in Case 13-G-0136 for a more complete description. Appendices J, K and L of the same report illustrate conversion program rebate amounts, market potential and estimated annual budget amount respectively.

C. Natural Gas Vehicles and NGV Pilot Program

Q. What programs does Distribution offer that encourage improving the environment and reducing dependence on foreign oil?

A. On June 28, 2011, Distribution filed a proposal with the NYPSC to allow the Company to promote the development of Natural Gas Vehicle ("NGV") applications in its New York service territory by permitting the Company to buy down (reduce) the initial cost of installing NGV equipment at customer facilities and/or purchase of NGV's. On November 18, 2011, the NYSPC issued an Order (Case 11-G-0348) ("the 2011 Order"), approving the NGV Partnership Pilot Program.

On December 9, 2014 the Company filed revisions to P.S.C. No. 8 – Gas to extend its Partnership for Natural Gas Vehicle (NGV) Program to March 31, 2018. On May 15, 2015, the NYPSC issued an Order (Case 14-G-0551) ("the 2015 Order"), approving the NGV Partnership Pilot Program extension.

1 Q. Please provide a program overview.

2 A. Distribution's Partnership for NGV's program is designed to improve
3 the customer's NGV project economics by reducing the payback
4 requirements of the customer through a one-time cost buy down of
5 the NGV Refueling Station facility installation and/or purchase of
6 NGVs. The cost of the one-time facility cost buy down would be
7 recovered from the customer through the future incremental
8 transportation or sales service charges paid to Distribution by the
9 customer. This method assures that buy down costs will be borne by
10 the NGV customers on a project-by-project basis.

11 Q. What are the pilot programs objective and benefits?

12 The Partnership for NGV's program was developed in response to
13 requests from customers and our NGV partners that were actively
14 involved in the installation and operation of NGV facilities/vehicles for
15 customers. Customers and our NGV partners urged Distribution to
16 become directly involved in improving the marketability of NGVs.

17 The objectives of the Partnership for NGVs program include the
18 following:

19 • Improve project economics to meet the customer's payback

requirements;

- Develop flexible rates designed to meet project requirements;
- Provide one-time facilities cost buy down;
- Develop a set of measurable deliverables to evaluate the effectiveness of the pilot program and report back to the Commission; and
- Costs to be borne entirely by each project.

Promoting the development of NGV's would benefit Distribution from the high load factor and incremental volumes generated by NGV customers. This type of increased load helps Distribution spread out system fixed costs over larger throughput, and improves utilization of the system during the off-peak shoulder and summer months. The overall system improvement then is beneficial for Distribution's rate payers.

For commercial and industrial customers, NGVs allow them to reduce their overall fuel costs, while enhancing our environment and national energy security. NGVs would promote the state's ongoing efforts to maintain and attract employers to New York through reduced operational business costs and increased competitive statuses.

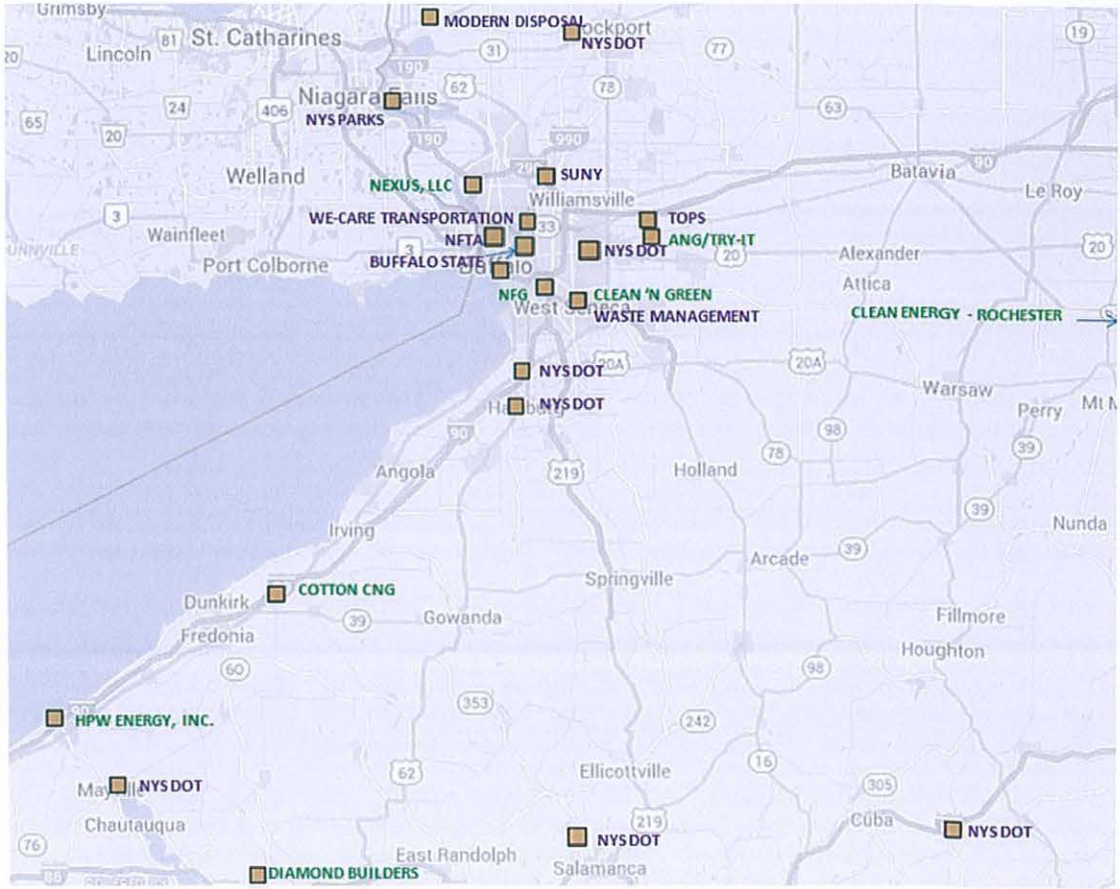
The 2009 New York State Energy plan recognized New York's leadership role in developing NGVs. New York can work with other states and with transportation and energy associations to influence vehicle manufacturers to produce alternative fuel vehicles of all types (light duty and heavy duty). Having a variety of vehicle types to meet their needs will allow public and private sector fleets to expand their use of these vehicles.

Q. How many customers have participated in the NGV Pilot Program?

A. To date, seven (7) customers have signed a contract and received an incentive through this program. This will result in an annual increased usage of 418,889 Mcf on Distribution's system. The total incentive amount given to these 7 customers was $1,175,596. In addition, we are currently finalizing a contract with another customer, which when complete will result in 8 customers under contract, a total incentive amount given out of $1,494,999 and a total annual increased usage of 610,889 Mcf. For more details on the NGV Pilot Program, please see Distribution's NGV Pilot Program Annual Report, which was filed on January 29, 2016.

Q. Regarding existing fueling infrastructures, where are public and private CNG stations located in Distribution's territory?

A. Please see the map below indicating both public and private CNG stations.



Public Refueling Stations
Private Refueling Stations

Q. What are Distribution's target markets within the transportation sector?

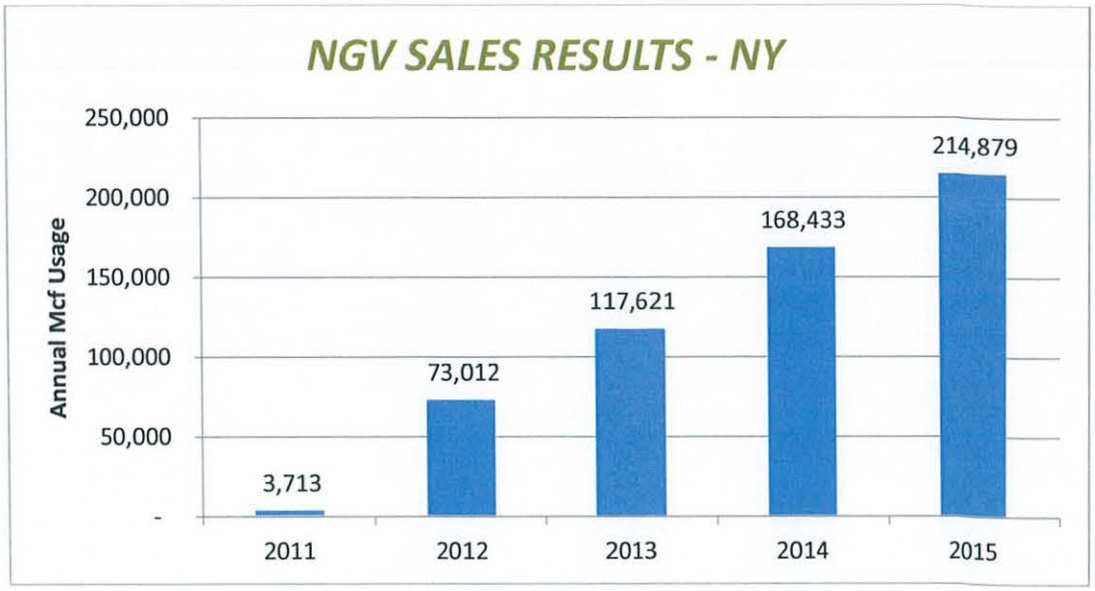
A. We have identified companies with substantial numbers of fleet vehicles, especially those with high fuel consumption per vehicle. Diesel fleets have shown some of the best economics, due to typically high fuel usage and higher fuel cost than gasoline. Replacing older diesel vehicles with clean operating natural gas vehicles also yields a positive environmental impact for the Company.

Q. How many customers have converted some or all of their vehicles to CNG?

A. At this point, approximately twelve customers.

Q. How have CNG sales increased over the past five years?

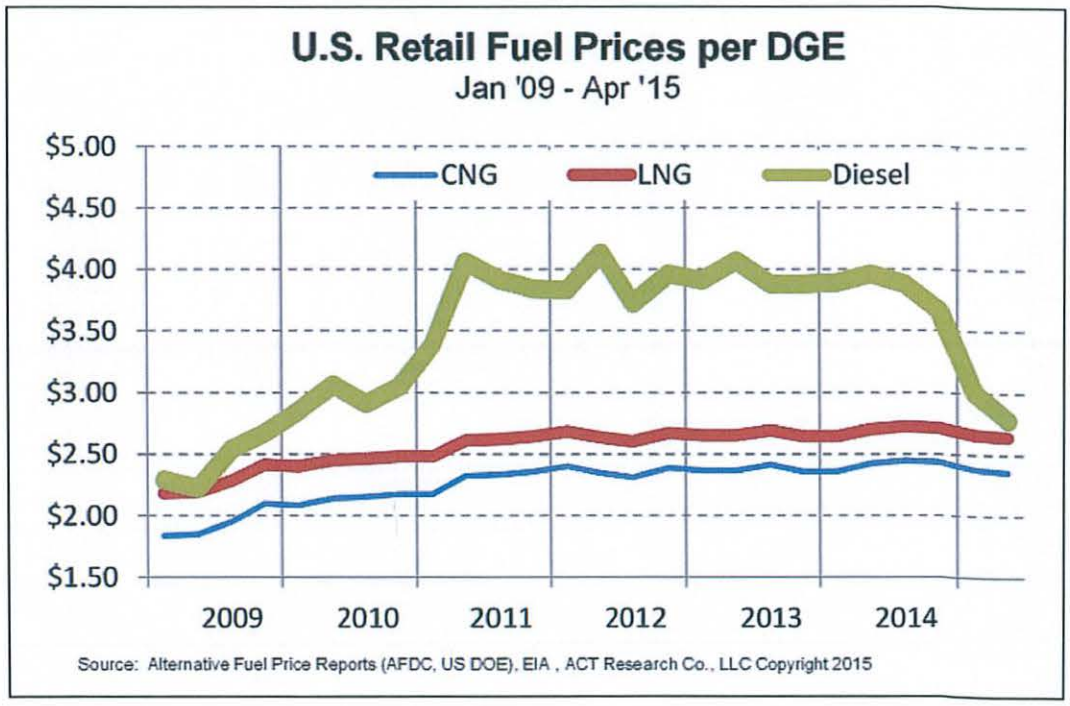
A. See the bar graph below showing annual CNG consumption by year.



1 Q. What types of activities comprise your marketing approach to
2 promote NGV's?
3 A. We have utilized a paid subscription service, "Fleetseek", which
4 provides the ability to sort and filter on many aspects of a public or
5 private fleet. In this way, we can prioritize on vehicle size, fuel
6 usage, geographic location, annual miles driven, etc. In addition,
7 Energy Services has been involved in several outreach and
8 education initiatives.
9 Energy Services developed a new NGV sales and marketing
10 brochure to assist with sales calls and training sessions. The NGV
11 Pilot Program is promoted in this brochure.
12 We have also developed a section of our corporate website
13 dedicated to education regarding natural gas vehicles. This also
14 includes a map of current WNY CNG refueling stations open to the
15 public.
16 Energy Services has taken a lead role in a local advocacy
17 organization, Clean Communities of WNY ("CCWNY"), as a member
18 of the steering committee.
19 We developed and participated in numerous events, including 2013
20 through 2016 Buffalo Auto Show, CNG 101 training workshops,

1 customer Open Houses and tours of existing refueling stations, all of
2 which helped promote the economic and environmental benefit of
3 converting to natural gas vehicles.
4 Energy Services has been able to develop relationships with
5 consultants, equipment vendors, suppliers, contractors, trade groups
6 and funding agencies. These resources have proven to be
7 invaluable when developing this NGV market.
8 Energy Services has worked with NEXUS and Tops Markets to
9 enhance their station Grand Openings to increased turnout and
10 outreach of events.
11 Q. What is the current economic situation for companies considering
12 natural gas vehicles?
13 A. Although NGVs have become more popular over the past few years
14 in our service territory, there are some obstacles to continuing this
15 growth trend. The rapid decrease in prices of diesel and gasoline,
16 combined with relatively consistent natural gas prices (see chart
17 below), has increased the payback period for natural gas vehicles.
18 As an example, a business with 20 heavy duty vehicles investing in a
19 moderate CNG fueling system and converting their trucks, would see

a simple payback go from 2 years at $4/gallon diesel cost to 4.6 years at the current cost of $2.25/gallon diesel cost.



Q. Why does Distribution want to offer market based pricing at its CNG station in Buffalo?

A. Distribution wants to encourage the establishment of more new CNG infrastructure, to promote the market. We do not want to discourage this private investment by acting as a deterrent to the developer/owner.

Q. What is the status of Distribution's public CNG fueling station and the Company's desire to move to market based pricing?

A. Below is the background and history which summarizes our progress towards market based pricing at Distribution's retail CNG station in Buffalo.

January 2013 – Distribution requests approval from Commission for credit card billing, market based pricing and negotiated pricing

August 2013 – Commission issued an Order approving credit card billing and defers decision on market based and negotiated pricing.

December 2014 – Distribution meets with an entity that had concerns over Distribution's NGV Tariff schedule.

June 2015 - Distribution meets with Commission Staff and presents concept of third party retail operator for Mineral Springs NGV station, in which third party operator to offer phased-in market pricing. Distribution reviewed RFP process to select third party operator.

August 2015 – Distribution reviewed formal proposal for third party operator with Commission Staff, and received approval to proceed with the RFP.

November 2015 – Distribution issued RFP's to the bidder list.

1 January 2016 – Distribution evaluated the response and tentatively
2 selected a proposed operator.
3 March 2016 – Distribution reviewed the proposed operator with
4 Commission Staff, and received approval to proceed to contract
5 negotiations.
6 April/May 2016 – Distribution expects to finalize contract with
7 operator and begin customer outreach.
8 June 2016 – Distribution expects to implement new retail operator
9 relationship with successful bidder.
10 **Section 6 – Closing**
11 Q Are you familiar with the rules governing transactions between
12 Distribution and its affiliates approved in Case 04-G-1047?
13 A. Yes, with respect to their application to the Energy Services
14 Department.
15 Q. To your knowledge, is the Energy Services Department in
16 compliance with these rules?
17 A. Yes, Energy Services employees are required to familiarize
18 themselves with, and fully observe, the affiliate rules governing
19 transactions between Energy Services and Distribution's marketing
20 affiliates.

1 Q. Does this conclude your panel testimony?

2 A. Yes, it does at this time.

BY MR. NICKSON: (Cont'g.)

Q. And, Panel, do you also have a document in front of you entitled the Rebuttal Testimony of the Energy Services Panel consisting of 23 pages of questions and answers?

A. Yes.

Q. And was that document prepared by you or under your supervision?

A. Yes.

Q. Do you have any changes or corrections to that testimony?

A. No.

Q. If I were to ask you the same questions -- questions today would your answers be the same?

A. Yes.

Q. And do you adopt this testimony as your sworn testimony in this proceeding?

A. Yes.

MR. NICKSON: Your Honor, I ask that the rebuttal testimony of the Energy Services Panel be incorporated into the record as if given orally today.

A.L.J. LECAKES: Granted. At this point in the transcript it should appear in the folder

Company Rebuttal Testimony. The file Energy Service Panel Rebuttal Testimony.

BY MR. NICKSON: (Cont'g.)

Q. And, Panel, did you also sponsor four exhibits to your rebuttal testimony which were identified as ESP 1 through ESP 4?

A. (Solomon) Yes.

Q. And were those documents prepared by you or under your supervision?

A. (Eck) Yes.

(Solomon) Yes.

Q. And do you have any changes or corrections to those documents?

A. No.

(Eck) No.

MR. NICKSON: Your Honor, I ask that the exhibits that were identified as ESP 1 through ESP 4 be marked for identification.

A.L.J. LECAKES: Yes. ESP 1 will be marked as Exhibit 255. ESP 2, 256, ESP 3, 257 and ESP 4, 258.

MR. NICKSON: The panel is ready for cross examination.

A.L.J. LECAKES: Thank you. Staff.

CROSS EXAMINATION

BY MS. WOEBBE:

Q. Good morning, gentlemen.

A. (Panel) Morning.

Q. Will you please begin by turning to your rebuttal testimony, page 2 and direct you to lines 14 through 16. Gentlemen, isn't it true that your panel agrees with staff's recommendation that the gas expansion plan with an annual 750,000 dollar funding from the capacity release in the off system sales revenues should continue through this rate term?

A. (Eck) Yes, that's correct.

Q. Please explain how the company has used this 750,000 dollars to expand service and what enhancements are being made.

A. We've used that -- that funding for a number of things. We've conducted some focus groups of non-customers to determine what they feel they need to convert from an alternate fuel to natural gas. We've used that also to subsidize or reduce the prepayments and surcharges for the pilot programs that we're also implementing. And we're also using that money for both the gas conversion rebate program which is just being implemented and the LIURP conversion program targeted to

add low-income customers.

Q. Is there a neighborhood expansion program that utilizes some of this funding?

A. We -- we don't have a neighborhood expansion program per se. What we've been doing is identifying clusters of non-customers and implementing -- implementing pilots in a phased planned approach starting with Wilson and Richmond which were larger pilots of 258 of 580 customers. Now we're moving into the second and third phases of smaller to midsize streets or region but we don't have an actual neighborhood or planned region in place.

Q. Okay. Let's discuss those Wilson, Richmond pilot programs you just referenced. Please turn to Exhibit 256 which was just marked. That's the gas network enhancement program table included as an exhibit in your rebuttal testimony.

So the first column is labeled the total number of homes. It lists Phase 1, Phase 2 and Phase 3 home locations totaling 1,523 customer homes, correct?

A. Correct.

Q. How many of these 1,523 customer homes have propane systems?

A. I don't have that number right at my fingertips. I would guess it's roughly a third or so. There's also oil and electric, but that could be obtained and given.

Q. And the third column is labeled number of applications to date, also lists Phase 1, Phase 2 and Phase 3 applications totaling 750 customer homes that have applied to convert to natural gas through this -- this gas network enhancement pilot program, correct?

A. Correct.

Q. How many of these 750 customer homes have propane systems?

A. Again, I don't have those figures readily available, but it's probably on the order of a third.

Q. And are these figures of the number of propane systems included in your annual reports?

A. I'm not sure what annual report you mean.

Q. Doesn't the company provide an annual report to the Public Service Commission detailing the pilot programs that --?

A. Yes. Yes, we do. Yes, that is included in there to my knowledge.

Q. And what's the average cost to convert a home from a propane system to a gas system?

A. It depends. There's -- there's two ways you can go. You can change out an orifice on the furnace or boiler and that might cost on the order of 100 dollars or so, maybe 200 dollars with labor. Or if you don't want to change out the orifice, if you want to do a complete furnace change out that could be -- then again on the efficiency level that could be 3,500 or so dollars.

Q. Does National Fuel have a rebate program for homeowners in order to convert from a propane system to a natural gas system?

A. Yes, we do. We're just implementing a gas conversion rebate program which only applies to furnace change outs not propane -- propane orifice change outs. We're offering twice what the CIP, Conservation Incentive Program rebate is which ranges from about 650 dollars to about 1,400 dollars depending on the type of equipment.

Q. And has this customer rebate increased since it was first offered?

A. Well, it just -- it's just getting rolled out now. Our standard rebate was for just the upgrade from a standard to a high efficiency rebate. So

this new rebate is double what that old conservation incentive program rebate was.

Q. Is there a particular reason why the company increased the rebate levels or rolled out this new rebate?

A. Some of the feedback from our customer focus groups was shown that for whether it's a non-heating customer who already has service, they have to change out their furnace. There's an impediment with the high cost that can be a major barrier. Whether it's a skips non customer on the main or a non-customer near the main, they have main line costs, but there's also the appliance cost.

And in our feedback and those focus groups they told us the pilot program was help for the mainline cost but the appliance cost was a large piece of it. And our current CIP rebate wasn't quite large enough in their minds, so hence, we came up with a double rebate for the conversion just for space heating conversion.

Q. Would you agree that if a customer converts their home with the first way that you mentioned that costs 100 to 200 dollars a rebate may not be necessary?

A. Correct. Which is why we don't offer it.

Q. Looking again at this gas network enhancement program, given that column 4 lists the number of conversions to date at 218 total customer conversions and the company has received 750 applications to date, do you agree that there are 532 remaining customers who submitted applications but have not yet converted to natural gas?

A. Correct.

Q. And in the fourth column labeled number of conversions to date where Phase 1 has 160, Phase 2 has 58 conversions to date and Phase 3 has no conversions to date, can you please clarify the date range, both the start and the end date for these numbers?

A. Wilson was -- it really depends on when it's completed. Wilson the main line was in -- in the summer of 2015. Richmond, we're still working on that. That's going to be completed by the end of calendar 2016. The Phase 7 or Phase 2 -- all 7 locations of the main line is in this past summer. And then Phase 3 some of those, roughly 5 might get in by the end of this calendar year. The remaining will probably be in by next summer or early fall.

Q. And just to clarify, when did Phase 1 customers begin receiving service?

A. The main line was in, to the best of my knowledge, in the summer of 2015.

Q. And when did Phase 2 customers begin receiving service or will based on --?

A. Phase 2 literally just got completed this past summer. They were all small, 1 or 2 or 3 streets of 20, 30 customers. So it was fairly easy to put that in versus Wilson which is a pretty large mainline extension.

Q. On page 5 of your rebuttal testimony, lines 12 through 14 the panel testifies, we do not agree with including the Phase 3 pilot program customers as part of the rate filing, is that correct?

A. Correct.

Q. And does this extend to including Phase 3 customers in forecast for this rate filing?

A. I would defer that to either Mr. Meinl or Mr. Crahen possibly on the volumetric forecasting.

(Crahen) Yeah, I -- I would say that that's a question really for the volumetric forecast panel.

Q. Based on your testimony that you do not agree with including Phase 3 pilot program customers as part of the rate filing, can you logically extend that

to disagreeing with including Phase 3 customers in forecasts during this rate filing?

A. (Eck) Again, I would probably have to defer to Mr. Meinl and the rates department on that.

Q. Mr. Crahen, can you offer your --?

A. (Crahen) Yeah, as to the volumetric forecast panel is put together the company's five year forecast with respect to sales volumes and number of customers the -- the point with which the company's taking exception to is including growth from these projects in customer growth projections from that forecast. But this question, as we stated, is better suited for that panel to --.

Q. Okay. Thank you. Is this panel generally aware that compensation and benefit incentives are tied to customer conversions?

A. (Eck) I'm not sure. If you could elaborate what kind of compensation and benefits are you referring to.

Q. Executive compensation and benefit incentives.

A. I really don't know.

(Crahen) I'm not aware of any. All of the company's executive compensation with respect to

metrics is included in the company -- National Fuel Gas Company's proxy statement which is filed publically with the FEC So it's disclosed by the company in there.

Q. So generally this panel would not have any knowledge of that?

A. (Panel) Correct.

Q. All right. Shifting topics to discuss the company's natural gas vehicle pilot programs. We already discussed this, but just to confirm, does the company provide an annual report on the natural gas vehicle pilot program to the commission?

A. (Eck) Yes, we do.

Q. And would you agree that your panel does not agree with staff's proposal to incentivize diesel vehicle conversion to natural gas?

A. Yes, and that's really because we feel that the largest market for natural gas vehicles is commercial fleets which are all typically on diesel anyway. And they either build their own station to refuel their vehicles onsite or they use a public station. There is significant cost to purchase the vehicles, to build the stations, and we feel that our pilot program has been more than adequate to meet the needs of those customers.

We've got 6 customers on it, 7 -- a

seventh just about to sign a contract so the incentives we can offer through the pilot program tend to be 50, 100, 200, 300,000 dollars. So we feel that's a much better incentive than a more prescribed rebate like you get with an appliance for a vehicle.

Q. Well, particularly your panel disagrees with staff's proposal regarding reporting requirements 90 days after the commission's decision in this rate case because the company already provides annual reports to the commission, is that correct?

A. Correct. And the staff's testimony asked us for -- for us to give them information on the size of the potential fleet that's out there for diesel conversions. In our rebuttal testimony we mentioned that the FleetSeek subscription database that we subscribe to has information on these fleets, just does not give the fuel type but for the Class 7 and 8 vehicles we're looking at, the lion's share of those are on diesel. So we're reporting a lot of that within our already annual report for the pilot.

MS. WOEBBE: That's a good segue. Your Honor, may I approach and present interrogatory response DPS 136? This was not included in the group exhibit but --.

A.L.J. LECAKES: Absolutely.

BY MS. WOEBBE: (Cont'g.)

Q. Gentlemen, do you recognize that document?

A. Yes.

(Solomon) Yes.

Q. Is that document an accurate representation of your discovery response to staff's interrogatory DPS 136?

A. (Eck) Yes.

MS. WOEBBE: Your Honor, I request that this exhibit be marked for identification and entered into the record.

A.L.J. LECAKES: We'll mark it now as Exhibit 259. We'll move all exhibits at the end of the hearing into the record. So 259 for identification, a two-page document front and back of National Fuel Gas distribution response to Department of Public Service request for information. Proceed, Counsel.

BY MS. WOEBBE: (Cont'g.)

Q. Gentlemen, isn't it true that FleetSeek identified 342 companies with substantial numbers of fleet vehicles that have high fuel consumption per vehicle which have some of the best economics for

conversion?

A. It does list a large number of -- of fleets. Not all those vehicles or not all those fleets have a lot of vehicles. We do have fleet size in that database, but we don't have the fuel type. But a lot of the fleets tend to be medium to smaller fleets. And you're right. These are all valid prospects for natural gas vehicles. What we're struggling with right now is the collapse of the diesel and gasoline prices and it has shrunken the spread between natural gas and diesel which has pushed out the payback and made the economics that -- that much more difficult even for the larger fleets.

Q. Can I refer you to page 80 of your direct testimony? On the top of page 80 of your direct testimony. Let me know when you get there.

A.L.J. LECAKES: No, you're good. Go ahead.

BY MS. WOEBBE: (Cont'g.)

Q. The panel states that you have identified companies with substantial numbers of fleet vehicles especially those with high fuel consumption per vehicle which are these 342 companies identified in Exhibit 259. Farther down lines 5 through 7 the panel states, replacing older diesel vehicles with clean

operating natural gas vehicles also yields a positive environmental impact for the company.

Is it the panel's position that changing economies has made these 342 companies no longer meet the criteria identified in your testimony?

A. It's made it more difficult to make the economics work for some of these fleets. There are increasing fleets that are looking at beyond the economics to environmental sustainability aspects of -- of natural gas vehicles. But still it usually comes back at the end of the day to the economics. And it definitely has made those 340 fleets a tougher sell.

Q. Is it generally true that the more natural gas vehicle conversions you can capture the more company revenues will increase?

A. Yes.

(Crahen) Yes, that's correct.

(Solomon) Sounds correct.

Q. And isn't it true that a survey of fleet vehicles to identify diesel fleets may help the company's conversion efforts?

A. (Crahen) So although FleetSeek provides a publication service for the different types of fleets that are close by or that could be, quote unquote,

prospect as Rob mentioned, the actual conversion conversation with those customers is based on the economics of the deal. As that spread between gasoline and that -- or sorry, diesel and natural gas compresses, it doesn't matter at all -- or well, not at all, but it doesn't matter for the most part what -- it doesn't matter at all for the most part what type of -- of customer interest there are.

There -- the customers just are interested as much because it's not as cost effective. So despite our best efforts to prospect these customers, if the economics aren't as good as they were previously, there's a lot of things outside of the company's control that can prevent us from converting these customers to natural gas service despite the most, you know, despite having a good, well running program or not, it comes down to the economics not the company's -- not things that the company can control at the end of the day.

(Eck) I would also add that in our rebuttal testimony ESP 3 is really kind of an update of the chart you're referring to one page 80 of our testimony which looks at what we've got not only now but in a pipeline. These are actual customers with actual vehicles totaling 383 vehicles and 611,000 MCF is either online now

or contractually committed through 2021.

So this is a little bit misleading or inaccurate and it gives you a snapshot for 2015. But the market is -- is continuing to grow based on our marketing efforts in 2013, 2014 and 2015.

Q. Just to clarify your direct testimony states that diesel fleets have shown some of the best economics due to typically high fuel usage and higher fuel costs than gasoline and that's at the top of page 80 which we were just on. Is it this panel's position that that sentence should be amended in light of the changing economies?

A. Well, I think best is a relative term. They -- they show the best economics but those economics tend to change as the price of diesel fluctuates. We're still seeing some of the bigger fleets having paybacks of anywhere from 4 to 8 years depending on whether they have to build a station themselves or refill at a public station as opposed to what the earlier paybacks were, 1 to 2 years when diesel was much -- was much more expensive. So it is a little relative. It's -- it's still good it's just not quite as good as it was a couple years ago which makes that sale that much more difficult.

Q. Is the sale still worthwhile for

National Fuel to pursue?

A. Definitely.

(Solomon) Absolutely. One thing I would add there too, it is a function of economics but it's not always just the fuel. One of the things that we've noticed from prospecting a number of these trucking fleets is there's other factors that weigh into it like business growth and business gain. We've seen that from a number of fleets that actually have been required from their end users that they have to have a sustainability plan.

So what they're -- we're finding is some of these trucking fleets are going in the door to get the business and showing that they have a sustainable truck. Being a C and G truck, therefore that company can go to their customer and say that, yes, we can take credit for that green measure. So we're seeing that. So we're not -- we're recognizing that the economics may not be great today because of the -- the diesel fuel cost, but we are still getting out in front of them and introducing them to these concepts and -- and learning more about the best practices that some of these fleets are -- are running into out in their day to day businesses.

Q. Does this panel believe that a rebate

program to the fleet owners might make the conversions more successful or capture more fleet conversions?

A. (Eck) I mean I -- I think it's our opinion right now that the -- the pilot program works for the one off vehicle or for the company that's converting 150 vehicles regardless of the size of the vehicle, size of the station, the conversion, we're able to give that customer a rebate, if you will, it is just a buy down through the **NGB** pilot program. The only difference is it's not a prescriptive check a box and you get it. There's a commitment of a 6 year contract that assures we get the -- the usage and the revenue associated with that -- that volume.

Q. Just to be a bit more specific, would a rebate program incentivize more customers to convert to natural gas vehicles for their fleets?

A. (Solomon) I would say it would depend on the dollar amount on the rebate. If you're going to give 100,000 dollar rebate then yes. But you might -- if you're going to give 1,000 dollar rebate then, no, it's probably not.

Q. And just to clarify would that be a total rebate or a per customer rebate?

A. (Eck) It will be per vehicle.

Q. Per vehicle.

A. Right.

(Eck) Per customer, per vehicle.

Q. 100,000 dollars per customer per vehicle?

A. Oh, I'm sorry no. I thought you meant your -- your version of the rebate. I'm sorry. Ours is per customer, yes.

(Crahen) But just to be clear, there's -- there's nothing precluding those customers from participating in the program that's already in place today.

Q. Correct.

A. So a rebate could reasonably be seen as a duplicate incentive which is something the commission's very much interested in examining today in the energy efficient context. Given all the work that's going on with the Clean Energy Advisory Council especially with duplicative incentives in that working group there, I don't know if it's in the company's best interest to confuse the market place and just overcomplicate it, let's say, by having multiple offerings out there in the market that customers further have to evaluate when considering the economics of making that switch to natural gas.

(Eck) And one -- one further the -- a rebate would be difficult in that it would have to be either a one size fits all or tailored to the type of vehicle or the annual usage. The pilot program allows us to customize the incentive to the actual customer, the number of vehicles, their mileage, the fuel they use. So it's tailored directly to their -- their project and their economics.

A -- a checkoff rebate would be simpler but our rebate is relatively simple and straightforward. There's no application. We just calculate it and enter into a contract with them.

Q. Gentlemen, is it true that you cannot obtain fuel type information from the FleetSeek data that's provided?

A. (Solomon) That's correct.

Q. Is it true that not identifying fuel type of the fleet vehicles may be a barrier to participation in the natural gas vehicle conversion program?

A. I would say no in respect to FleetSeek because I think based on the type of class of vehicle we can accurately assume that they're most likely a diesel user. So that would be someone we would actively pursue

and prospect them.

(Eck) We actually filter on Class 7 and 8 vehicles which are almost exclusively diesel fuel. So even though we don't know the exact fuel we've got a pretty -- pretty good indication just based on it by -- by the size of the vehicle what it uses.

Q. So for clarification purposes those 342 companies that FleetSeek identified would be assumed to be diesel fuel vehicles?

A. (Solomon) Yes.

(Eck) Primarily.

(Solomon) And I would just add one thing to that. Yes, we did query down a 342 but sometimes when you call the company it's falling under that company umbrella but it doesn't necessarily mean the vehicles are stationed there. So we found a few times where that number was inflated at times I guess.

(Eck) Right. That's a flaw of the database.

MS. WOEBBE: Thank you, gentlemen. No further questions, your Honor.

A.L.J. LECAKES: Mr. Mager.

CROSS EXAMINATION

BY MR. MAGER:

Q. Good afternoon, panel.

A. (Panel) Good afternoon.

Q. I just have one line of questioning for you and it relates to your direct testimony. Can you please pull that out and go to page 7 and just let me know whenever you're ready?

A. (Eck) Okay. We're okay.

Q. Okay. On -- starting on line 4 you discuss how NFG is affected by a variety of market forces and has competition with other fuels. And then you say this kind of inter fuel competition occurs primarily in our larger commercial and industrial customer markets. Do you see that?

A. (Panel) Yes.

Q. When you reference larger commercial and industrial customers, does that include SC 13 transportation customers?

A. (Solomon) Yes.

(Eck) Correct.

Q. And is it fair to say that SC 13 customers are among the most price sensitive customers you serve?

A. Yes, I would say it depends on each customer but that's a -- a relative --

Q. Okay.

A. -- generality.

Q. And then on the bottom half of page 7 going on to page 8 you discuss various pricing strategies that the company employs, do you see that?

A. Yes.

(Crahen) Yes.

Q. Okay. And too -- would you agree that that pricing impacts whether certain customers retained or in some cases increased throughput on your system?

A. (Eck) Yes, our main -- our -- our -- like -- like Mr. Meinl summarized for us very well and kind of stole our thunder, the transportation rate is just -- just one element of the overall price. So to the extent that those rates go up that is an impact but conversely the -- the record low commodity costs due to Marcellus shale has more than offset any -- any real price increase or sensitivity in many cases for our customers.

Q. That would not apply to pipeline bypass threats, for instance, where it’s gas on gas, correct?

A. Correct.

Q. And in those types of situations typically if a customer is able physically to bypass then

it may come down to a matter of economics, would you agree with that?

A. Correct. And we have within our tariff on our SC 13 the ability, as Mr. Meinl mentioned, to selectively discount and flex our rates to meet the competitive threat based on how severe it is.

Q. And have customers ever made the decision to bypass the company without getting a -- without getting a competitive pricing proposal?

A. Yeah, it's -- we've -- we've had some that have bypassed us a long time ago. But on the flip side in the last couple years we've had a lot of those bypass customers come back to us because the economics were so strong within our system. But -- and that has happened occasionally, but they usually come to us first.

Q. Okay. And you -- on page 8 you discussed this around the middle of the page, but would you agree that where -- where efficient it's beneficial to increase gas throughput?

A. What -- what line are you referring to? Lines? 7?

Q. About line 7 starting.

A. (Crahen) Can you define what you mean by beneficial?

Q. Providing -- does the -- does the company have an interest in maintaining or in some cases increasing gas throughput on its system?

A. (Eck) Yes, as we mention there by adding usage it spreads out our fixed costs over a large base which has a -- has an impact of lowering our cost of service to all customers.

Q. Okay. Now could you -- and on page 8 you start discussing the bypass threat, correct?

A. Correct.

Q. And on page 9 you indicate starting on line 4 that bypass threat is largely a function of economics.

A. Uh-huh.

Q. And then page 10 you -- you start discussing the actual bypass threat that the company faces, do you see that?

A. Yes.

Q. Okay. And you’ve indicated that I believe 7 customers were lost due to bypass starting on line 11.

A. That's correct.

Q. Were they large transportation customers if you recall?

A. Both of them to my knowledge have never been a customer of ours, the 2 largest ones. The other ones were transportation customers.

Q. Okay. And then starting on page 11 you discuss high risk customers in terms of bypass, do you see that?

A. Yes.

Q. Okay. And then with respect to those high risk customers, are they transportation customers currently?

A. Yes.

(Solomon) Yes.

Q. Okay. So they -- are they currently served under SC 13?

A. (Eck) Yes.

(Solomon) Yes.

Q. Okay. And same question on lines 14 through 16 with respect to medium risk customers. Are all or a good portion of them SC 13 customers?

A. Yes.

(Eck) Yes.

Q. And finally same question. At the bottom of the page with respect to low risk customers.

A. Yes, they're all primarily SC 13

customers.

Q. And just so the -- the record is clear, how -- how do you characterize customers as high risk, medium risk or low risk?

A. We do it on a very high macroeconomic level the way we look at the cost to install a line to the customer's bypass source. We look at the associated savings which they would incur by not being our customer and then we come up with a -- a payback on that -- on that investment. High priority, high risk customers are deemed to be those with less than a 5 year payback. Medium priority are 5 to 10 years, and low priority are greater than 10 years.

Q. Thank you. You testified earlier that increasing throughput on the system reduces the cost of service to all -- all customer classes, do you recall that?

A. Yes.

Q. And would you agree that the converse is also true, that when the -- when the company loses throughput, for instance, due to pipeline bypass by transportation customers that will ultimately increase the cost of service to all customer classes?

A. (Solomon) Yes.

(Eck) Yes. The other customers have to make up for that revenue loss.

Q. Okay. And then on page 19 you discuss the -- some of the economic factors that impact the company's throughput and you discuss on lines 12 through 14 that there have been approximately 12 major plant closings in the last 5 years, do you see that?

A. Uh-huh.

Q. Were those customers generally transportation customers of the company to your knowledge?

A. (Solomon) I would say generally. Not sure if all of them are -- were.

(Eck) Yeah. There might have been a couple smaller SC 3 rate customers. But in general I would say, yes, they're all probably SC 13.

Q. Okay. And then on page 20 starting on lines 12 you -- you talk about 400 of your large volume accounts and then you -- you testify that these customers operate in very competitive markets and have many choices for their energy needs, do you see that?

A. Yes.

Q. Would it be fair to say also that a large percentage or perhaps all of those large volume accounts are SC 13 transportation customers?

A. (Solomon) That would be fair to say.

(Eck) There's a couple cogeneration customers on a special rate, but by and large, yes, all SC 13.

MR. MAGER: Thank you. I have nothing further, your Honor.

`A.L.J. LECAKES: Does any other party have cross examination? No one indicated it.

EXAMINATION

BY A.L.J. LECAKES:

Q. Panel, counsel for staff, Ms. Woebbe asked you about Exhibit 256, the gas network enhancement program and the number of applications to date. I believe the question was approximately how many of those are propane customers. And -- and the answer given was an estimate of about a third.

What's the source of the -- the knowledge behind the estimate? Is it just a guess or -- or is there some actual reason to believe a third is a fairly accurate number?

A. (Eck) To those that have applied we actually on -- on the application know the fuel type.

Q. Okay.

A. But in some cases they haven't applied

so we have to use public information and sometimes it's not available.

Q. Okay. One of the staff recommendations that they made, that the -- the panel takes issue with in its rebuttal testimony, and I can get the cite if you need it but you might know this -- remember this offhand is that the company seek new franchises in order to -- to continue to enhance and expand its system. Again, the company panel takes issue with that.

What kind of thought processes at the company, what kind of programs are there that the -- the company goes through when it considers out of -- out of existing franchise expansion?

A. Well, I mean, usually the -- we're not actively seeking to expand our franchise. Usually it comes to us reactively. They -- they -- they come to us asking to -- for instance, it's how a Canadice -- a sliver of their customers have asked us to expand. We are open to gas franchise expansion, but on a case by case basis we have a lot of opportunity within our -- our service territory both non-heating customers, non-customers right on our mainline which are diffuse all over the territory.

And then thousands of non-customers

every year are mainline which these new pilot programs are trying to attract. So we have limited resources of personnel and capital and we're kind of addressing each -- each gas franchise expansion on a -- on a case by case basis. Our major issue we're trying to work through is some of the complexity of the actual franchise due diligence, the environmental, the regulatory especially when sometimes it doesn't pertain to the real small segment of customers like in Canadice that we're open to serve. So, again, we're not against it but we really look at it on a case by case basis based on trying to work it into all the other expansion activities we're doing.

A.L.J. LECAKES: Great. Thank you. I have nothing further. If the company wants to approach for a redirect.

Any redirect, Counsel?

MR. DELVECCHIO: Yeah, your Honor. We just -- just a couple redirect.

A.L.J. LECAKES: Very good.

REDIRECT EXAMINATION

BY MR. DELVECCHIO:

Q. If I could please ask the panel to take a look at the, again, the gas network enhancement program which was Exhibit ESP 2 that Ms. Woebbe had asked

you about. If -- if you just could turn your attention to the number of applicants -- applications to date and the number of conversions to date under Phase 1 for Wilson and Richmond. Could you just explain briefly why the percentage stands where it's at right now?

A. (Eck) Sure. So the way the pilot was designed was the pricing for both the upfront prepayment and the surcharge was targeted to be about 1,800 dollars for a prepay 30 dollar a month surcharge. But it was based on assumption that total number of customers eligible in that pilot region would connect over -- 75% of them would connect over a 10 year period. So that surcharge and prepayment which varies for each pilot is based on that.

To the extent that it's above those target levels, we have money available to try and incentivize that and bring it down to those target levels that our new service department has told us is needed to make the work. So but there's also a little bit of misleading information in this table in that -- so -- so first of all that 10% or that 75% over 10 years, for instance, if you look at Wilson, there's 228 homes.

We've already connected 79 which is roughly 30%. We had converted 30% in 2 years. So we're

well on the way to connecting 75% percent over 10 years. The other pilots are a little further along or not quite as far along but all of them we're very confident that we can meet or exceed that 75% over 10 years.

Second is the actual conversions to date. There's a little bit of a lag time between when the actual mainline is announced to the customers and when the conversion occurs. First of all to get the mainline in we have to secure right of ways which can be time consuming. We have to bid the project out to contractors, award the contract, install the pipe depending on weather, time of year, terrain issues. That can make it a multi-phase project sometimes, lag it further.

So that's just to get the mainline in the ground. Then once the mainline is in front of the actual home then the customer has to convert. The beauty is the mainline is there. They can convert when they want whether it's this year, next year or the following year. But the actual conversion may not occur for 2, 3 or 4 years and there's a lot of factors there from timing issues with the customer.

They might have oil or propane and they got a full tank and they don't want to just -- they want -- they -- they're going to take a year to empty it

over the heating system and then do it the following year. There's issues of coordinating quotes with the heating contractor to get pricing. Then actually having the equipment installed. So there's a lot of timing and logistics that cause these conversions to not occur boom, boom, boom, you know, right after the mainline goes in. And the mainline itself can take a while too.

Q. Okay. And just -- and you've been keeping staff up to date on the progress under these gas network enhancement programs?

A. Yes. We have annual filings and we've had informal meetings with staff roughly every six months or so either in person or over the phone.

Q. And they've been pretty pleased with the progress they're making under -- under Phase 1?

A. Yes. They'd like to see it move faster and we're trying but, like I said, there's timing issues and logistics that are really outside of our control.

MR. DELVECCHIO: Okay. Thanks. Nothing further, your Honor.

A.L.J. LECAKES: Ms. Woebbe, any recross?

MS. WOEBBE: Just one question, your

Honor.

RECROSS EXAMINATION

BY MS. WOEBBE:

Q. At what point in time in the pilot project process is the customer outreach conducted?

A. The customer outreach is conducted when we get internal approval to actually do the pilot. Then we have to actually work with our engineering and operations department to schedule it, so we typically send out mailings letting customers know that it's coming. The actual mainline might not be coming for 3, 6 months or so until we can actually get out there and put the mainline in. But once we have internal approval and staff's approval to do the pilot we then begin the outreach.

Q. Generally do you have an idea of how long internal approval and staff approval usually takes?

A. We've kind of -- again, because we have limited capital resources and limited personnel resources -- resources, we've been pretty much on an annual basis of doing 1 phase every year. And the actual process we've got probably 30 or 40 candidates right now for our next Phase 4. It's a matter of just, you know, vetting them, deciding how much we can afford within our capital budget.

How much we can realistically put in -- in the ground. We don't want to over promise and under deliver. We want to under -- yeah. So it -- it's a fine line we walk. We want to make sure that the line is in in -- in a timely fashion and not get -- get ahead of ourselves and promise it too soon.

MS. WOEBBE: Thank you.

A.L.J. LECAKES: Okay. At this point we're going to break for lunch. When we come back from lunch we'll start. Ms. Jorgensen, please remind me if I forget. We're finally going to get your exhibits in. We'll also mark EnergyMarks' testimony and exhibits, get that into the record.

And then what we're going to do is we're going to change up the order in accommodating Mr. Sano and so we'll do those brief preliminary things and then we'll start with a -- is there order of preference of policy panel versus gas, the -- the staff gas policy and supply panel?

MS. WOEBBE: No, your Honor.

A.L.J. LECAKES: Why don't we do the policy panel first since it's the longer one, get that out of the way. Then we'll do the gas policy and supply for staff. And then -- excuse me, and then we can move on to

the NFG gas supply and policy panel, so.

UNIDENTIFIED SPEAKER: When do you want us back?

A.L.J. LECAKES: Yeah. So we're going to break now. We'll come back at 1:30. All right. Thank you. Off the record.

(Off the record)

A.L.J. LECAKES: All right. Let's go back on the record.

Mr. Marchiori, for Energy Mark, would you like to make a -- a -- an appearance? Just tell us your name and your business address, please?

MR. MARCHIORI: Good afternoon.

Gary Marchiori. Energy Mark, 6653 Main Street in Williamsville, New York. Energy Mark's a energy supplier, primarily operating in New York and Pennsylvania under National Fuel System. We represent 20 percent of the through-put for the transportation volumes to end-users on that system. Our reason for here is on -- primarily --.

A.L.J. LECAKES: All right. I find that Energy Mark has a -- a -- an interest in this case, permission to grant party status.

Mr. Marchiori, could you please stand where

you are and -- and just raise your right hand?

Do you swear or affirm that the testimony you're about to provide in this proceeding is the whole truth?

MR. MARCHIORI: I do.

GARY MARCHIORI; Sworn

EXAMINATION

BY A.L.J. LECAKES:

Q. Please sit.

Mr. Marchiori, you've provided me with a C.D., pursuant to my instructions that has a document on it that consists of including a cover page, 7 pages titled, The Direct Testimony of Gary Marchiori, Tim Wright and Greg Chaffey. Was this document prepared by you and under your direction?

A. Yes, it was.

Q. And as we sit here today -- well, how -- are there any changes that you would make to the testimony as provided on that disc?

A. Not at this time.

Q. Okay. As we sit here -- here today, if you were to be asked these questions, would you provide the same answers that appear in this testimony?

A. I would.

A.L.J. LECAKES: Okay. On my own motion, I am going to grant the allowance of the testimony of Energy Mark to be put into the record of this transcript of the hearing. So, I will direct the Court Reporter for the disc that he was just handed, the file is called Energy Mark Testimony dash NFGD Gas Supply Panel And again, that's the Energy Mark testimony.

STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

PROCEEDING ON MOTION OF THE COMMISSION AS TO
THE RATES, CHARGES, RULES AND REGULATIONS OF
NATIONAL FUEL GAS DISTRIBUTION CORP.
FOR GAS SERVICE

DIRECT TESTIMONY OF

GARY A. MARCHIORI, TIMOTHY D. WRIGHT, CRAGG CHAFFEE

ON BEHALF OF ENERGYMARK, LLC

AUGUST 26Th 2016

1 **DIRECT TESTIMONY OF**

2 **GARY A. MARCHIORI, TIMOTHY D. WRIGHT, CRAGG E CHAFFEE**

3 **ON BEHALF OF ENERGYMARK, LLC**

4

5 Q. PLEASE STATE YOUR NAME AND ADDRESS**.**

6 A. My name is Gary A Marchiori.

7 My office is located at 6653 Main Street, Williamsville, NY 14221

8 Q. BY WHOM ARE YOU EMPLOYED AN IN WHAT CAPACITY?

9 A. I am employed by EnergyMark, LLC as President.

10 Q. PLEASE DESCRIBE YOUR QUALIFICATIONS.

11 A. I hold a Bachelor of Science degree in Business Administration, Marketing/Accounting

12 from Indiana University of Pennsylvania, and a Master of Business Administration from

13 the State University of New York at Buffalo. In 1985 I started my energy career at

14 National Fuel Gas Distribution in the Energy Services Department. In 1994 I transferred

15 to National Fuel Gas Supply, as an Interstate Marketing representative. In 1996 I joined

16 Texaco Natural Gas as Northeast Regional Manager of Natural Gas Marketing.

17 In 2002, I formed NOCO Energy Marketing (NEM). In 2006, Constellation Energy

18 (CNEG) purchased NEM and I became CNEG Regional Vice President. In 2010 I formed

19 EnergyMark, after purchasing the CNEG New York and Pennsylvania assets.

20 EnergyMark is a private company with a publicly held partner, South Jersey Industries of

21 Folsom, NJ.

1 Q. DO YOU HAVE ANY PROFESSIONAL EXPERIENCE THAT IS RELEVANT

2 TO THE TESTIMONY PROVIDED HEREIN?

3 A. Yes. I have held natural gas and energy related positions since 1985 and have been an

4 active energy entrepreneur since 2002, primarily operating on the National Fuel system.

5 I have been a board member for 20 years of NYS Independent Oil & Gas Association and

6 also serve as Vice-chair of Buffalo Niagara Partnership's Energy Council. I also serve on

7 the Board of Clean Communities of Western NY, which is a federally and privately funded

8 organization addressing reduction in petroleum use for transportation.

9 Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE NEW STATE PUBLIC

10 SERVICE COMMISSION?

11 A. No.

12 Q. HAVE YOU PRESENTED EXPERT TESTIMONY BEFORE ANY OTHER

13 REGULATORY COMMISSION?

14 A. No.

15 Q. PLEASE STATE YOUR NAME AND ADDRESS.

16 A. My name is Timothy D. Wright.

17 My office is located at 6653 Main Street, Williamsville, NY 14221

18 Q. BY WHOM ARE YOU EMPLOYED AN IN WHAT CAPACITY?

19 A. I am employed by EnergyMark, LLC as Vice-President.

20 Q. PLEASE DESCRIBE YOUR QUALIFICATIONS.

1 A. I hold a Bachelor of Arts degree in Political Science, from Niagara University, and a
2 Master of Business Administration from Niagara University. In 1988 I started my energy
3 career at National Fuel Gas Distribution in the Energy Services Department. In 1996 I
4 transferred to National Fuel Resources, as an Energy Trader. In 1998 I joined Texaco
5 Natural Gas as Northeast Regional Trader of Natural Gas. In 2002, I became a partner
6 in NOCO Energy Marketing (NEM). In 2006, Constellation Energy (CNEG) purchased
7 NEM and I became CNEG Regional Manager. In 2010 I partnered with Gary A. Marchiori
8 to form EnergyMark.
9 Q. DO YOU HAVE ANY PROFESSIONAL EXPERIENCE THAT IS RELEVANT TO
10 THE TESTIMONY PROVIDED HEREIN?
11 A. Yes. I have held natural gas and energy related positions since 1988 and have been an
12 active energy entrepreneur since 2002, primarily operating on the National Fuel system.
13 Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE NEW STATE PUBLIC
14 SERVICE COMMISSION?
15 A. No.
16 Q. HAVE YOU PRESENTED EXPERT TESTIMONY BEFORE ANY OTHER
17 REGULATORY COMMISSION?
18 A. No.
19 Q. PLEASE STATE YOUR NAME AND ADDRESS.
20 A. My name is Cragg E. Chaffee.
21 My office is located at 6653 Main Street, Williamsville, NY 14221

1 Q. BY WHOM ARE YOU EMPLOYED AN IN WHAT CAPACITY?

2 A. I am employed by EnergyMark, LLC as the General Manager.

3 Q. PLEASE DESCRIBE YOUR QUALIFICATIONS.

4 A. I hold a Bachelor of Science degree in Business Administration, from the State University

5 of New York at Buffalo, and a Master of Business Administration from the State

6 University of New York. In 2010 I started my energy career at EnergyMark and have

7 been actively involved in Operations, Trading, Scheduling, Contract Administration,

8 Capacity and Asset Management on Dominion Pipeline, Columbia Gas Transmission,

9 Empire, Tennessee Gas Pipeline, and National Fuel Gas Supply.

10 Q. DO YOU HAVE ANY PROFESSIONAL EXPERIENCE THAT IS RELEVANT TO

11 THE TESTIMONY PROVIDED HEREIN?

12 A. Yes, I am a member of Clean Communities of Western NY and the Independent

13 Power Producers of New York.

14 Q. WHAT IS THE PURPOSE OF YOUR GROUP'S TESTIMONY?

15 A. The purpose of our testimony is to address the following issues.

16 The primary concerns of EnergyMark, supplier to large volume and mass market

17 customers behind National Fuel's city gates in NY are:

18 <u>1. Sales service rates which are non- market price based.</u> These sales service rates are subject

19 to Gas Supply Adjustments which include substantial credits for Capacity Release and off

20 system sales, these credits are unevenly applied to just Sales Service Customers and not to

21 all rate payers. The utilities price to compare has become an increasingly difficult price to

1 compete with and provide meaningful savings to end users.

2 2. Selective capacity release programs: The current practice, by the LDC, of releasing long
3 haul capacity to on system Marketers at maximum rates, which have receipt points pricing
4 that are not competitive with market area receipt point pricing. NFGD is sourcing up to
5 97% of its supply from regional/Marcellus receipt points. With 50% of NFGD system
6 demand provided by Marketers, an equal amount of regional capacity and access to lower
7 cost receipt points is needed to provide the benefit of lower cost supply to local
8 consumers. Access to current gas supply points recently acquired by NFGD. The utility
9 has recently contracted with Empire Pipeline for capacity reaching the Pennsylvania
10 Marcellus region. That capacity has not been shared with Marketers behind the
11 NFGD system.

12 3. Capacity Release Programs: The utility currently has an active capacity release program
13 that limits sales of capacity to a reservation only based offer. To increase capacity release
14 revenues and better match market needs, especially to the power generation market,
15 volumetric capacity release should be offered by the LDC. Rate payers would benefit
16 from this change from increased capacity released revenue sharing, and through lower
17 overall supply costs. Power generators would have increased reliability of service and be
18 allowed cost recovery of transportation assets used in a volumetric manner.

19 Q. WHAT ARE THE IMPACTS TO MARKETERS OF THE CURRENT LDC SUPPLY
20 SHIFT TO REGIONAL SUPPLY POINTS?

21 A. Given the ability of the LDC to commit, long term, to upstream pipeline capacity,

significant market power and access to lowest price regional supply has created a vertical market supply advantage to the LDC. Access to Marketers to these low price regional receipt points through all forms of mandatory and general capacity releases have been limited and do not reflect the receipt needs for 50% of throughput that Marketers supply on system.

Q. DOES THIS CONCLUDE YOUR GROUP'S TESTIMONY?

A. Yes, at this time.

Thank you.

Ms. Jorgensen, I understand that PULP has some exhibits that you would like marked before we move on to the next panel?

MS. JORGENSEN: I would, Your Honor.

As we've discussed off record a couple of times, PULP had certain company responses to information requests that PULP had posed to the company, that did not fit the parameters for the group exhibit. But nevertheless, I spoke with the company and they were willing to stipulate verbally here today on the foundational requirements for these additional IRs and -- information requests, rather and so I put them all in additional exhibit with just two additional, non-information request documents.

The first is a -- they're both -- they're both information that was obtained online but are referenced in a hyperlink to William D. Yates' corrected testimony and so we're providing them for your convenience. I've distributed to all parties those -- those packets that are available online along with our proposed information requests.

A.L.J. LECAKES: Now -- now, how are those documents compiled? Are they compiled in two separate

stapled sets, one of IRs and one of the printouts of the hyperlink documents?

MS. JORGENSEN: Yes. I can -- I can give you a copy --

A.L.J. LECAKES: Yes, please --

MS. JORGENSEN: -- but you should --.

A.L.J. LECAKES: -- please approach.

MS. JORGENSEN: These are the PDFs from the hyperlinks. This is just one question that was 49 and 74 --

A.L.J. LECAKES: Okay.

MS. JORGENSEN: -- pages and this is the rest, which I've tabbed for everybody, in terms of the individual IRs.

A.L.J. LECAKES: Okay. Thank you.

I think the way I'll do this is I will mark for identification, since it's in its own kind of compiled form, what appears to me to have 74 numbered pages and is labeled by the front, PULP dash 2 dash 49, page 1 of 74 Witness Customer Service Panel. It's a National Field Gas Distribution Cooperation’s Response to Public Utility Law Project of New York Company.

Am I correct -- or is Ms. Jorgensen correct, that the company has stipulated to the fact that

they prepared this response in the regular course of business?

UNIDENTIFIED SPEAKER: Yes, your Honor.

A.L.J. LECAKES: Okay. We'll mark that as Exhibit 260.

I then have a -- another page -- a several-page document that consists of several responses to PULP IR. The first being PULP dash 3 dash 53, PULP 52, PULP 48, PULP 46, PULP 39, PULP 38, PULP 31, PULP 29, PULP 28, PULP 27, PULP 9, PULP 8, PULP 7, PULP 4 and PULP dash 1 dash 3.

MS. JORGENSEN: Your Honor, I'm wondering if we might have skipped 46. Between 48 and 45, I --

A.L.J. LECAKES: I do --

MS. JORGENSEN: -- I --.

A.L.J. LECAKES: -- have a PULP 46 here, you're correct. It -- it -- it appears between PULP 48 and PULP 45.

Unless there's any objection, I'd like to -- to mark this as a single exhibit, rather than breaking it up and marking them all individually and then if parties feel the need to reference these in their post-hearing briefs, they can just refer to it as what will be Exhibit 20 -- 261 and then further the -- the number of

the PULP IR.

So we'll -- well, the company did -- where -- the response -- are these all directed to NFG, Ms. --

MS. JORGENSEN: Yes.

A.L.J. LECAKES: -- Jorgensen?

MS. JORGENSEN: Different -- different panels.

A.L.J. LECAKES: Right. But they're -- they're all to the company itself?

MS. JORGENSEN: Correct.

A.L.J. LECAKES: Not to staff or any other party?

MS. JORGENSEN: No.

A.L.J. LECAKES: Okay. Company, are you ready to stipulate that you prepared the responses to all of these PULP IRs in the regular course of business?

MR. NICKSON: Yes, your Honor.

A.L.J. LECAKES: Okay. We'll mark that as 261 for identification.

Next, I'm looking at a document handed to me, which appears to be a printout. The cover page has a picture on it and the title is Customer Incentives for Energy Efficiency Through Electric and National -- Natural Gas Rate Design. It starts on an unnumbered page and then

ends on page D dash 2. PULP has represented that this is a -- simply a print out of a hyperlink document that appeared in -- was it Mr. Yates' testimony or Mr. Yates' -

MS. JORGENSEN: Corrected --

A.L.J. LECAKES: -- exhibit?

MS. JORGENSEN: -- direct testimony.

A.L.J. LECAKES: Corrected direct testimony.

Have all the parties had a -- a chance to look at this document and are there any objections to it?

Okay. We'll mark it as Exhibit 262.

Finally, I have a three-page, front and back, although not every back has writing on it, document. The title of the document is Utility Rate Design, where at -- at least it seems to be a printout of a webpage that is titled Utility Rate Design slash Energy dash Utilities dash Communications slash Utility dash Rate dash Design dot html.

Again, as I understand it from Ms. Jorgensen, this is a printout of a hyperlink in Mr. Yates' testimony, is that correct?

MS. JORGENSEN: Yes, your Honor.

A.L.J. LECAKES: And are there any party

objections to marking this as an exhibit?

Okay. We'll mark it as Exhibit 263.

Again, if parties want to formerly object to exhibits that are being marked and haven't had a full chance to look at them, we will take further objections tomorrow at the close of the hearing, if necessary.

MR. NICKSON: Your Honor, the company as two additional exhibits that have not been marked yet. They are responses to request for admission. We --.

A.L.J. LECAKES: Please bring them forward.

MR. FAVREAU: And your Honor, also, I'm not sure if the August 26th letter, that we a couple times --

A.L.J. LECAKES: Right.

MR. FAVREAU: -- it’s actually on the CD with the corrected and additional exhibits, if that’s been marked for identification.

A.L.J. LECAKES: It -- I don't believe it has yet.

MR. FAVREAU: Okay.

A.L.J. LECAKES: We can do that.

MR. FAVREAU: I don't have any hard copies of it, but I --.

A.L.J. LECAKES: Would you prefer -- well, would the parties prefer to have a -- a hard copy of that?

It was a letter to NFG, correct?

MR. FAVREAU: Correct.

A.L.J. LECAKES: Yeah.

MR. FAVREAU: It was a letter from NFG to the department.

A.L.J. LECAKES: From NFG, okay, to the department.

MR. FAVREAU: And it's on DMM, I believe, so 11M and I forget the exact details.

A.L.J. LECAKES: It might be easier if we do that later, when I do have a hard copy just so I can write the number on it and just keep it for my records. So, if you could please remind me later in these proceedings.

MR. FAVREAU: Okay. We'll -- we'll bring the hard copy.

A.L.J. LECAKES: Great. Thank you.

All right. So I'm looking at -- the company handed me first, a NFG Distribution Cooperation Request for Admission, directed to the Utility Intervention Unit, Department of Consumer Protection. Don't see a date on this. It's a single page.

U.I.U. is Mr. -- Ms. O'Hare, you're familiar with this response that was prepared?

MS. O'HARE: Yes.

A.L.J. LECAKES: Okay. And Mr. Color (phonetic spelling), prepared this in the regular course of business?

All right. So we will mark this as Exhibit 264.

And I also have a National Fuel Gas Distribution Cooperation Request for Admission to Department of Public Service. It doesn't identify the responding party, but I believe it was Richard Davi, is that correct?

MR. FAVREAU: Correct.

A.L.J. LECAKES: All right. And Mr. Davi prepared this in the regular course of business responses?

MR. FAVREAU: Yes, he did.

A.L.J. LECAKES: We will mark this at Exhibit 265.

All right. Is anyone aware of any other preliminary matters that we should deal with before we move on to the next panel or witness?

Okay. Very good.

Who from staff is presenting the panel?

MS. WOEBBE: I am, your Honor. Bridget Woebbe.

A.L.J. LECAKES: Ms. Woebbe, please call your next panel.

MS. WOEBBE: Staff Policy Panel.

A.L.J. LECAKES: All right. Could all the panel members please recite their name in turn and then their business address? Actually, do all of you share the same business address?

MR. FAVREAU: Yes.

A.L.J. LECAKES: All right. So, if one of -- if -- if maybe the spokesperson could identify himself and then his business address. We'll just assume that the same address will be used for all the other members of the panel.

MR. RIDER: My name is Eric Rider. My business address is 3 Empire State Plaza, Albany, New York 12223.

MR. DAVI: Yes. My name is Rich Davi and I am the same address in Albany.

MR. AUGSTELL: Michael Augstell and I have the same address in Albany.

MR. STOLICKY: Christopher Stolicky, same address in Albany.

MR. SANO: John Sano, same address in Albany.

MS. FERRERI: Monica Ferreri, same address in Albany.

MR. PASINELLA: Michael Pasinella, same address in Albany.

A.L.J. LECAKES: Okay. Panel members, with the exception of Mr. Sano, please stand and then all panel members please raise your right hand.

Do you all swear or affirm that the testimony you're about to give today is the whole truth?

THE PANEL: Yes.

ERIC RIDER; Sworn

RICHARD DAVI; Sworn

MICHAEL AUGSTELL; Sworn

CHRISTOPHER STOLICKY; Sworn

JOHN SANO; Sworn

MONICA FERRERI; Sworn

MICHAEL PASINELLA; Sworn

A.L.J. LECAKES: Okay. You may be seated.

Ms. Woebbe, will you please lead the panel in to getting their testimony and exhibits, if any, into the record?

DIRECT EXAMINATION

BY MS. WOEBBE:

Q. Members of the Staff Policy Panel, has

the pre-filed testimony for this case been prepared by you or under your supervision?

A. (Rider) Yes.

Q. Is the 40-page document before you that testimony?

A. Yes.

Q. Do you wish to make any changes to this testimony?

A. Yes.

Q. What changes would you like to make to your pretrial testimony?

A. On page 28, line 14, rate year should be changed to calendar year 2017.

Q. Are there any other changes you would like to make?

A. On line 17, the word rate year should be changed to calendar year.

Q. Are there any other changes you would like to make?

A. On page 39, per IR response NFGT.B. D.P.S. 176, the term electrofused should be changed to buttfused and that shows up on line 9, 12 and 14.

MR. FAVREAU: And your Honor, I'd like to point out that there is corrected -- this panel presented

corrected testimony that that -- put Mr. Stolicky in place of Mr. Wade. These corrections, though, are not on the corrected testimony.

If you'd like, we could resubmit that.

A.L.J. LECAKES: The corrections that Mr. Rider just --

MR. FAVREAU: Correct.

A.L.J. LECAKES: -- recited?

Correct. Yeah. I -- I see that. That's fine.

MR. FAVREAU: Whatever you prefer.

A.L.J. LECAKES: Yeah.

If you could provide me with a -- a --

MR. FAVREAU: A recorrected?

A.L.J. LECAKES: -- actually you can -- yeah. A recorrected one and you can just email that to me.

MR. FAVREAU: Okay.

A.L.J. LECAKES: And I would just like to clarify for the record, that the corrections that were made by Mr. Rider, he -- he noted a correction on page 9, on page 12 and on page 14.

MS. WOEBBE: Your Honor, may I clarify those corrections?

A.L.J. LECAKES: Oh, okay. Yes. Go ahead.

MS. WOEBBE: Those corrections are on page 28, line 14 and 17. The correction is changing the words rate year to calendar year 2017.

A.L.J. LECAKES: Right.

I -- the -- the last ones are the ones I'm concerned with because the word changed.

MS. WOEBBE: Yeah.

A.L.J. LECAKES: The first two are electro and then the last one is electric -- I just lost it. It was --.

MS. WOEBBE: Your Honor, those corrections are on page 39 --

A.L.J. LECAKES: Right.

MS. WOEBBE: -- line 9, line 12 and line 14.

A.L.J. LECAKES: Right.

MS. WOEBBE: Electrofused plastic joint should be changed to buttfuse.

A.L.J. LECAKES: Yeah. Although the last one, if you look at it on lines 14 and 15, is actually -- it -- it -- it's a typo, I think because it says electric-leaf used as opposed to electrofused. So -- but I -- I think that the -- the -- the -- the change itself is -- is

identical in change. I just wanted to clarify because if anyone looked at the -- the initially-filed document, it wouldn't say electro, it would say electrically-fused there.

MR. FAVREAU: Should -- I -- I ask that question to the panel.

Should that -- is that the correction term, or should that be buttfused?

MR. RIDER: You want to answer?

A.L.J. LECAKES: The -- the first two are --.

MR. FAVREAU: That should also --

A.L.J. LECAKES: So the correction --

MR. FAVREAU: -- be buttfuse?

A.L.J. LECAKES: -- is --

UNIDENTIFIED SPEAKER: Yeah.

MR. FAVREAU: Okay.

A.L.J. LECAKES: -- is accurate.

Okay. All right. Go -- proceed, Ms. Woebbe.

BY MS. WOEBBE: (Cont'g)

Q. Members of the panel, if I were to ask you today the same questions as those, which are in your prepared testimony, would your answers to those questions

be the same as you have written in the prepared testimony noting those corrections just made on pages 28 and 39?

A. (Rider) Yes.

MS. WOEBBE: Your Honor, I move to incorporate into the record the staff policy panel's testimony, as if orally given today.

A.L.J. LECAKES: That's granted.

Right now, as indicated, there was a copy supplied on the disc that was handed to the Court Reporter yesterday that's listed as Staff Policy Panel Testimony, Clean. That does not incorporate all of the corrections made today. To the extent that we get a -- an electronic version of that sent to me by email, I will forward it on to the Court Reporter and that should be inserted, the -- the file and I will provide specific instructions in that email when I send it on.

MR. FAVREAU: Thank you, your Honor.

BY MS. WOEBBE: (Cont'g)

Q. Members of the staff policy panel, did you prepare or identify any exhibits to accompany your testimony?

A. (Rider) No.

MS. WOEBBE: Thank you.

Your Honor, the panel is prepared for

cross.

A.L.J. LECAKES: I turn it over to the company. I assume NFG has some questions.

MR. MILLER: Thank you, your Honor.

CROSS EXAMINATION

BY MR. MILLER:

Q. Good afternoon, Panel.

A. (Pasinella) Good afternoon.

Q. Let's start off talking about your recommended earning-sharing mechanism. It begins at page 5.

You stated, line 15 of page 5, that the earning-sharing mechanism maintains an incentive for the company to increase efficiencies. Do you see that?

A. (Augstell) Yeah. I'm sorry. Yeah. What -- what line?

Q. Line 15, I believe.

A. Yes.

Q. If there were no earning-sharing mechanism, would be company have an even greater incentive to increase efficiencies?

A. Yes.

I -- it -- it would still be beneficial to increase efficiencies without that.

Q. Is it your position that a company that is more efficient than average should earn more than an average rate of return?

A. Could you rephrase the question a little? Rephrase it?

That's kind of -- I mean, I'm kind of confused because you just -- or just state it again?

Q. Do you want me to repeat it?

A. Yeah.

Q. Okay. Is it your position that a company that is more efficient than average should earn a higher rate of return than the average company?

A. (Rider) Did we say that in our testimony, or are you proposing a hypothetical?

Q. It's the letter, Mr. Rider.

A. (Augstell) I -- could you just -- the last part of question, I'm -- it's just the question's a little confusing.

You're -- you're talk -- you're talking about just companies in general? Any company? Any type of company? Any industry?

Q. No, Mr. Augstell.

I'm just -- I'm saying in -- in -- in our regulated industry, companies regulated by this

Commission, is it your position, or do you believe, that a company that is more efficient than the average company, should earn more than an average rate of return on equity?

A. I mean, I would say that it's -- if a company's necessarily more efficient that they wouldn't -- if you're talking in the context of -- of a -- a return that's granted in a rate case that if they turn out more -- a company's more efficient that -- that they're -- are you saying they should be given a higher return?

(Rider) It's my understanding that -- that the Commission sets a fair rate of return and it's the utility's opportunity to either earn that return or earn a higher rate of return, if it is able to run its business more efficiently.

Q. Thank you, Mr. Rider.

My understanding of your testimony here, with respect to the earning sharing is -- one of the reasons you're recommending it in this case, is in the event that you're imputed one-percent productivity adjustment for the Barcelona Project, is great -- is insufficient to capture productivity from that project, is that correct?

A. Can you point me to the testimony where we state that?

Q. Look at page 6 starting at line 12, Mr. Rider.

A. So where it says we propose an additional 1 percent productivity adjustment be imputed in rate year, to ensure that customers see the benefits of efficiencies resulting from -- both from implementation of the new computer system and the retirement of the legacy computer systems. However to the extent that the company realizes a greater amount of benefits from the new computer systems, the E.S.M, will ensure that customers receive a portion of those benefits. That's -- that's what we said in our testimony.

Q. Fine.

And if the -- if those benefits that you're imputing fail to eventuate, are you proposing a mechanism that would allow the company to capture the shortfall between your imputation and the actual benefits?

A. No.

MR. MILLER: Your Honor, may I approach the panel?

A.L.J. LECAKES: Yes.

MR. MILLER: Your Honor, this -- I'm going to ask the panel some questions on a -- a discovery response they gave in -- it's IR NFGDPS 168, which is in

Exhibit 254, which is the group IR exhibit.

A.L.J. LECAKES: Okay. Great.

Proceed.

BY MR. MILLER: (Cont'g)

Q. Panel, if you'd refer, please, to your response to questions C as in Charlie and you see there you answered, Staff does not measure productivity at industrial companies, other than regulated utilities?

A. (Davi) Yes.

Q. Okay. Are you saying that staff measures productivity at regulated utilities in New York?

A. If you want to respond to that, go ahead.

(Off-the-record discussion)

A. (Cont'g.) Mr. Miller, we responded to an earlier IR regarding that same matter and we responded that we did not measure that productivity.

BY MR. MILLER: (Cont'g.)

Q. Thank you, Mr. Davi.

Panel, would you agree that the concept of an earning-sharing mechanism arose in the context of multi-year rate settlements?

A. Mr. Miller, if I could just add, earlier regarding this specific E.S.M., there is a dead-

band in there that's allowing, I believe it's 50 basis points to be retained of excess earnings, let's call it. And that's worth roughly, I believe it's -- if my math's correct, that's three and a half million dollars of earnings that would be allowed to be retained for it's shared.

I just wanted to put that on the record just to clarify.

Q. Are you talking about the dead-band between the staff recommended rate of return on equity and where the earning-sharing mechanism you proposed would kick in --

A. Yes. That's correct.

Q. -- at 9.1 percent, I think it was?

A. That's right.

A.L.J. LECAKES: Mr. Miller, can you repeat your last question? That was -- was not answered that -- because I -- I lost where -- what the question was now.

MR. MILLER: Sure. I was just going to do that, your Honor.

BY MR. MILLER: (Cont'g.)

Q. It was -- the -- the pending question was, is it the panel's understanding that the concept of an earning-sharing mechanism arose in the context of

multi-year rate settlements?

A. (Augstell) Yes, I believe that's true.

Q. All right. Let's move on to another topic on page 18 of your testimony and the rest of my cross is going to take off -- off of this, but I believe on page 18, starting on line 3, you say you proposed a series of measures that will not only provide an opportunity for the company to increase its earnings, but also move it down the path toward increased energy efficiency. Do you see that?

A. (Rider) Yes.

Q. Okay. The first one I want to ask you about briefly is the gas-safety metrics for the -- I think Mr. Stolicky called it a N. -- NSA, is that correct?

A. NRA.

Q. NRA. I'm sorry. Must have NSA on my mind.

How much in -- and let me back up.

Would you agree that the maximum basis point NRA under those safety mechanisms is 150 basis points?

A. (Stolicky) Yes.

Q. Do you know how much that would

translate into dollars, roughly?

A. (Davi) Mr. Miller, was that 150 basis points? Was that the question?

Q. Yes.

A. Well, we indicated earlier that 50 base points is worth roughly -- I believe, it's -- I believe it was two and a half million, right?

Q. Yeah.

A. So, if we multiply that by 3, I -- I believe we're at -- it's -- if my math's correct, seven and a half million.

Q. Thank you, Mr. Davi.

And the next one discussed is the customer-service metrics, correct? And I believe the company can lose up to about 1.8 million dollars on that, correct?

A. (Rider) Yes.

Q. And now you list a few of your proposals that might actually increase earnings or basis points on earnings, right?

A. Yes.

Q. And the first is determinations and uncollectible metric. Do you see that?

A. Are you referring to page 22, line 2?

Q. Yes.

Thank you, Mr. Rider.

That's not a symmetric -- that is a symmetrical metric, is it not?

A. (Ferreri) Yes.

Q. The company can either gain or lose basis points under that metric, correct?

A. (Rider) Yes.

Q. Are terminations covered under the Home Energy Fair Practices Act?

A. (Ferreri) Right now, I cannot recall.

Q. I'm sorry. I missed that answer.

A.L.J. LECAKES: I believe the witness answered -- t was, Ms. Ferreri, I believe she answered, right now, I cannot recall.

MR. MILLER: Okay.

A. To my knowledge, they would be.

A.L.J. LECAKES: And to my knowledge, they would be.

Could we -- are -- are you going to pursue more on the customer-service metric or -- that are being proposed because maybe we could shift the panel around for just a minute or two.

MS. FERRERI: I would recommend that if we

are going to go through detailed questions, that the entire policy panel -- the entire customer-service panel be present.

MR. MILLER: You know, I was going to suggest that, your Honor. Let me --.

MS. FERRERI: I think --.

MR. MILLER: I'm going to ask detailed questions --

A.L.J. LECAKES: Yeah.

MR. MILLER: -- on it tomorrow.

A.L.J. LECAKES: Yeah. They're already on tomorrow, so --.

MR. MILLER: Yeah.

A.L.J. LECAKES: Okay. Great.

MR. MILLER: We can do that.

MS. FERRERI: Because we will confer.

A.L.J. LECAKES: Yeah, that's fair. You've made your case.

BY MR. MILLER: (Cont'g)

Q. Now, I'm a little confused on your proposal on lowering unit costs on -- on the bottom of page 22. Do you see that?

A. (Rider) Yes.

Q. What is that proposal, exactly?

A. I believe the proposal starts on page 24, line 10 and it's really a concept. We're trying to be new and innovative and we would like to work with the company to -- to design a mechanism, so that it has an incentive to lower the unit costs and deliver its capital plan more efficiently and reward it for such efficiencies.

Q. Does the company competitively bid its capital projects?

A. I believe the company achieves its capital plan in a few different categories. Blanket contracts, bid contracts and then in-house work. So some of it, yes, is bid out. The in-house work may not be bid out.

Q. Well, the in-house work probably wouldn't be bid out, correct?

A. Right.

Q. Yeah.

And then that would be the company's own efficiencies in house, correct?

A. Can -- what -- what are you asking?

Q. Well, to the extent the company could reduce costs, that would be dependent how efficient the company would be, at least as it to its in-house work, correct?

A. That's one component, yes.

Q. Is there another component?

A. Well, the company structures its bids. It acquires materials for its jobs, it runs its business, if it could out efficiencies, it -- we're trying to create a mechanism to incent the company to -- to -- to find those efficiencies.

Q. How would that mechanism work, just briefly? I'm still not understanding how -- what you're envisioning here.

A. One way it could work is to benchmark the unit costs for leak-prone pipe and to the extent that the company can reduce its overall unit costs, it could be rewarded for those reductions in cost and, you know, we could apply a basis point for a percentage, say, that the company reduces its costs.

Q. I believe there's another -- one of the other proposals you're making is a further reduction in leaks, correct?

A. Yes.

I believe that's on page 26, line 11.

Q. And am I correct that under that proposal, the company could theoretically earn up to five basis points, were it to reduce 250 leaks?

A. Yes.

Q. Now, if you refer to page 21, line 1 -- page 29, line 1, rather. I'm sorry. Sentence that starts there, it says that this incentive is inclusive of the cost to repair the leaks. Do you see that?

A. Yes.

Q. I was unclear as to what you meant by the term inclusive of the cost to repair the leaks.

A. So our intent is that to the extent that the utility can reduce its leaks, that the incentive would cover both the cost to repair the leak and a -- a -- I guess, a reward for reducing the backlog.

Q. So, let's -- I -- let’s just --.

(Off-the-record discussion)

BY MR. MILLER: (Cont'g.)

Q. I -- I just want to make this clear, Mr. Rider. Okay?

So under the Gas Safety Panel’s proposal, the company would be required to meet a leak-backlog number of 1600 in the calendar year 2017, I believe, as long as Mr. Stolicky doesn't shake his head violently no.

A. We’ll agree.

Q. Okay. I’m correct.

A. (Stolicky) Yes.

Q. And now, in your proposal, I -- this panel's proposal, I take it is that the company -- if the company were to reduce that 1600 level by another 250 leaks, so what would we be down to? 15 -- 750? Is that right?

A. 1350?

(Rider) Yes.

Q. 2 -- 250 -- we it 250 cap -- reduction cap? So we're at 1600, 15 -- 750, right?

A. (Stolicky) That’s 25. 250 would be 1350.

(Rider) I think the proposal --

Q. Right. Okay.

A. -- is --

Q. Right.

A. -- is for --

Q. Right.

A. -- 50 leaks it's --

Q. You're dealing with lawyers, man. It’s never -- never a good thing to do.

A. -- it's 50 leaks is one basis point.

Q. Okay. So 50 leaks -- so if you went from 1600 to 1550, you get one basis point?

A. That's right.

Q. Okay.

A. And it -- that's inclusive of the cost to actually do the work.

Q. Okay. Now when you say inclusive of the cost, there's a cost per leak to repair the leak --

A. Correct.

Q. -- correct?

A. Yes.

Q. So, are you saying that company could also defer the cost to repair the leak?

A. No, it's inclusive of.

Q. So the company would expend the money to fix those 50 leaks --

A. Yeah.

Q. -- right?

And they'd earn one basis point for doing so?

A. Yes.

Q. Okay. Do you know how much it cost to fix an average leak? I mean, would it be about 1900 dollars a leak? Does that sound right?

A. I believe that's in UFRs -- there's a -- I believe that information is in UFR 115 and I can take

your number, subject to check.

Q. Okay. You said you can take that number subject to check?

So saying --?

A. Is that -- is that leak -- is that dollar amount emergency repairs, or just average repairs, or is that -- what -- can you clarify what that number means?

Q. I was under the belief that it's an average number for just normal-leak repair.

A. It doesn't include emergency work?

Q. I do not know.

Feels good to be on the giving end, doesn't it, Mr. Rider?

A. I, you know, I try to get these guys to let me practice all the time, but --.

Q. Okay. So let's stick with the 50 -- the -- the 50-leak example.

So 50 leaks, if -- if my number of 1900 is correct, fixing those 50 leaks would cost about 95,000 dollars, correct? Fifty times --.

A. Yes.

Q. Yes?

Do you know the value of one basis

point?

A. (Stolicky) Yeah. It's 50,000.

Q. Okay.

A. As discussed in the Gas Safety Panel yesterday about repairing type 3 leaks, there are other costs that are offset by reducing type 3 leaks and that would be money spent on the Public Awareness Plan to education customers, emergency response associated with responding to leak and odor calls that already exist. Plus, there is -- or there is a -- I'll call it a -- I'll -- well, I'll call -- you know our deal. When you're responding to leak and odor calls that are -- that are to nonhazardous leaks, you're pulling away resources from actual emergencies that could occur. So there are other costs that we have not quantified, but there are other costs and savings to the company by reducing type 3 leaks.

Q. Did you say 3 or 2, Mr. Stolicky? You -- you meant type 3 leak, right.

A. Type 3, yes.

Q. Okay. Now, on page 29, line 13 through 17, you're talking about technologies being pioneered by groups like the EDF Do you see that?

A. (Rider) Yes.

Q. Can you name any of those

technologies?

A. (Stolicky) I need to be careful how I answer this question. There are devices out there that are -- are optically-based, that measure plumes of methane that can be used to define leaks and you can plug them into different algorithms to do a -- a -- a calculation to try to estimate the leakage rates. There is also another device being used in a collaborative, out of the last Con Edison proceeding, but I can't talk about that because it’s -- it's in a confidential working group.

But we do point out in this testimony to talk to EDF, as -- as -- as one recommended approach.

Q. Did -- did you say you can't talk about the collaborative in terms of what's being discussed in the results, or the process of the collaborative?

Can you describe the process of the collaborative and what you hope to accomplish with it?

A. I don't know what I'm allowed to say out of that working group.

Q. Okay. Do you know if there's any utility in the United States that's using such a technology today?

A. Yes.

Q. Which one?

A. PG&E, Con Edison. Those are the two I know for sure -- that I know of.

Q. Okay. And in -- in what role are they using that technology? Is it as a pilot program or is it applicable to their system?

A. I'm trying to -- to understand your question.

They are using it for leakage detection on their system. Con Edison is piloting the technology this year, with the intent to use it as more of a permanent device in the future, maybe as early as next year.

Q. Do you know how Con Edison is piloting the technology, or is that part of the program you can't discuss?

MR. FAVREAU: I mean, if -- if they're doing it in some special way, then we shouldn't be discussing it.

A. I’m -- I’m processing this.

What they're doing in the working group is different than from what Con Edison. Con Edison has a device right now and they are out there running trials, comparing it to other leak-detection devices to try, to come up with a way they can use it for the

operation of their system.

BY MR. MILLER: (Cont'g.)

Q. Does that pilot have an end date of which you're aware?

A. No.

Q. Is it the intention of that pilot to share the results with other utilities in the state?

A. Not that I'm aware of.

Q. Okay.

A. (Rider) Well, we always encourage the utilities to work together and to learn from one another, so that we can improve safety throughout the -- the whole state.

Q. Are you proposing another positive incentive for damage prevention?

A. Yes. On page 30, line 13.

Q. And that would reward the company, if it were able to maintain a -- fewer than 1.50 damages per 1,001 call tickets, correct?

A. That's what it says on page 31, line 7.

Q. Okay. And if the company were to achieve that level, it would earn 4 basis points?

A. Yes. Per line 8 and 9.

Q. We -- we had this discussion yesterday with the Gas Safety Panel. Would you agree that the per damages due to mismarks, National Fuel is already the best performer in the state of the major utilities?

A. What timeframe are you referring to?

Q. The information I was looking at was the 2015 Staff Gas Safety Performance Report. I have that if you need it.

A. (Stolicky) Yes. We are the lowest rate for 2015.

Q. And isn't it also correct that for damages per company and company contractors, National Fuel is among the best performers in the state?

A. Yes.

Q. And isn't it also true that the only area where the National Fuel is not among the best performers in the state is third-party damages?

A. Yes.

Those are the two areas with the most room for improvement.

Q. And you would also agree, wouldn't you, that in that -- that area -- for that area, it is not entirely within the control of the company?

A. Correct.

Q. Let's move on to residential methane detection.

I was unclear here. Are there any basis points that you're proposing? Is this an incentive and if it is, are there basis points associated with it?

A. Well, what page are you on in the testimony?

Q. Starts at the bottom of page 31. It's just a heading there. Just move on to 32.

(Off-the-record discussion)

A. (Rider) Can you repeat the question?

BY MR. MILLER: (Cont'g.)

Q. Yeah.

I was just wondering, is there a basis-point incentive associated with that?

A. No.

Q. Okay. I was unclear by the testimony there, whether you believed that the new technology detectors have been commercialized yet.

What's your understanding of that?

A. (Stolicky) There is a new device being developed and that is not commercialized yet.

Q. Okay. Is -- is this mostly targeted at interior piping? That is, piping beyond the meter?

A. It is targeted at methane leakage inside a building, but as we all know, gas leaks can migrate into a building from the outside, as well as be on inside piping, whether it's upstream or downstream of a meter, if the meter is in the building.

Q. Are you aware that about 80 percent of National Fuel's meters are outside?

A. I -- I'm aware it's a large number.

Q. And are you also aware that when National Fuel renews a -- a -- a service, the intention is to put the new meter outside?

A. We like to hear that.

Q. Do you know if National Grid has a pilot program for methane detectors?

A. Which National Grid?

Q. I believe it would be KEDNY.

A. KEDNY, I believe, is starting in the current joint proposal in the future, but right now KEDLI, as part of a settlement agreement, has a pilot program now.

Q. Is that pilot program supported by rates?

A. No.

Q. Okay. Let's switch over to gathering

system motorization.

Is there a positive incentive for the company, with respect to odorizing a producer's gathering system?

A. (Sano) Well, our hope as a panel was to work with the company to try to develop one and we definitely thought there was a possibility for one, but we did not specifically testify to an exact one.

Q. I -- I guess I was a little unclear, Mr. Sano, on -- on what exactly the staff wants the company to do here, with respect to motorization of producing -- producers gathering lines.

A. Staff was interested in getting the company to work with us and the local producers as -- as participants together, to increase the safety of the gathering systems that are currently attached to the distribution company. With that regard, we do realize there are issues of liability between what the company owns and what the producers own, but since they are connected to the company, we did not feel there was a problem with asking the company to work together with us to try to determine who had odorization and who didn't.

Q. I guess some of the things that we were concerned about, Mr. Sano, was that the producer's

property is owned by the producers and the company's ability to patrol that property is limited. Would you agree with that?

A. Well, we do agree with it, but there is precedence within other commission decisions where personal property is required in order for a -- a different type of service to be allowed for a customer, or to even make sure that that customer's service is maintained. The best example I can give you is interruptible service throughout the state.

The local distribution companies do not own the alternate fuel facilities. They're owned individually by the individual customers, but as a requirement of the service, the companies do require that the customer prove that has had, in most cases it's a ten-day supply of alternate fuel, in order to be a non-firm customer.

So we have that as a precedence to basically identify that just because it's somebody else's property doesn't mean you cannot receive an affidavit, or confirm somehow that the situation does exist.

Q. Another thing that concerned us, Mr. Sano, was the requirement for odorizing producer gathering lines. It was our understanding that certain producer

lines do not even have to be odorized, for example, depending on their pressurization and their -- and their proximity to residences.

A. Yeah. I -- we believe you are correct.

My understanding is over a certain pressure and any -- any gathering line that's within a certain distance, I think it's 150 feet, of a residential or facility.

Q. All right. So, I -- I guess where that leaves us is we're not exactly sure if this is a concrete proposal, or just an invitation to discuss matters with staff.

A. Well, we wanted to see it as a concrete proposal, but I think that we'd be happy just to take a look at how we could weave in that, plus the need for the -- we wanted to weave together the need for odorization of the gathering lines and the meter-maintenance fees and the ability of a company to be attached to distribution.

Q. Okay. Next topic that staff talked about, as a possible incentive is called infrastructure enhancement. Do you see that?

I took that more as incenting customer

growth. Is that -- is that more correct?

A. Yes. I think the infrastructure enhancement involved with gas safety has enough of those other incentives. I think this one particularly was to -- to incent company who add additional customers.

Q. And that would potentially earn the company up to 5 basis points?

A. Yes. I think it -- the way we set it up was 1 basis point for every increase of 10 percent over the forecasted growth per year.

Q. Is -- is -- is this -- could this also be called an incentive to encourage the use of gas?

A. We prefer to use it as a policy to reduce the use of dirtier fossil fuels, primarily number two fuel oil or a heavier fuel oil and propane, which seems to be the majority of the customers that have been targeted in most of the pilot programs that we talked about earlier, with the Energy Services Panel this morning.

Q. Okay. The last one I see is a natural gas vehicle incentive. I don't see a -- a concrete proposal there.

Am I missing something?

A. Well, similarly, the discussion we had

earlier today with the Energy Services Panel, it -- it is unclear exactly how many of fleets that are being targeted have a certain portion of diesel fuels.

Now, we heard the panel this morning, discuss the fact that they already feel that the majority of the vehicles that are coming on the line are replacing diesel vehicles, but it appears that we don't know for sure and that's what staff was interested in trying to explore with the company. We understand the limitations of the software package they currently used to identify the fleets but we thought that something additional like a simple survey of the -- of the different three hundred and something other companies, might benefit us to the point where we get some feedback from a representative sample, to determine how much diesel was out there versus regular gasoline, or that wasn't diesel.

I -- our point, again, was to try to work with the company to develop something. That's why we were asking for a study, but by the word study, it could be something as simple as a simple survey --

Q. Okay.

A. -- as -- of a potential customer, potential fleets.

Q. So, in -- in terms of the programs we

just discussed, when I add them up, they come out by my reckoning, to about 14 basis points. Is that about right, if the company were to max out the incentives? 14, I believe.

A. You mean 44?

Q. Well, I'm not counting the uncollectibles.

A. (Unidentified speaker) Would it help you to list them out?

Q. Well, if the panel -- some of these programs seem more evanescent than not. So, if the panel will tell me what they get in terms of the -- the program and the basis points, maybe we can get an agreement.

(Off-the-record discussion)

A. (Rider) So, based on our analysis of our testimony here, I -- I know you said excluding uncollectibles, but we -- uncollectibles are worth 10, but excluding that, we had lowering unit cost at 10, leak-prone pipe miles at 10, the back log at 5, damages at 4 and 1 more here. Let me see. Infrastructure enhancements 5, plus there’s -- which is 34 and there are 2 other possibilities with odorization and NGB vehicles.

BY MR. MILLER: (Cont'g.)

Q. So excluding the symmetrical ones,

what do we have 20 -- 34 basis points?

A. 34 listed and there's -- like I said, there's 2 possibilities for odorization and N.G.V. We would include the -- the uncollectible piece though. I mean, that's a positive.

Q. The unit costs, rights, is -- is that a -- is that a concrete proposal yet? Is there a measurement --

A. No.

Q. -- in there?

A. The -- it's not a concrete proposal yet. We -- we really would -- because it is new, I think it would be beneficial for both staff and the company to work together to make sure that we understand how to set the bogeys and how to measure them.

Q. Okay. And -- and the leak-prone miles, that also is not concrete yet, is it?

A. That's concrete.

Q. Explain to me how it is.

A. I believe it's -- it’s explained on -- beginning on page 25 and over to 26. We would propose a P.R.A. of two pretext basis points for each full mile of leak-prone pipe main retired beyond the annual-minimum targets, plus the addition of one mile buffer. This

P.R.A. would be contingent upon the company meeting a minimum targets in each rate year and would be capped at 10 basis points per year.

Q. What year would that start?

A. So, this is where we get into the whole right year versus calendar year safety-related targets.

The safety performance metric -- metrics are measured on a calendar year and that -- our proposal begins the calendar year '17. So this incentive is tied to a calendar year.

Q. Is this intended as a replacement for the company's incentive proposal for leak-prone pipe?

A. Can you refer me to where that is?

Q. I believe it was Mr. Mainl’s testimony.

A. The one he proposed about 200 basis point incentive?

Q. It could be.

There -- what -- are you familiar with the company's proposal for leak prone pipe replacement if the -- if the company did more than the target level?

A. I'd have to go back to look at the -- the testimony, but we propose -- we're -- I guess we're

advocating for our proposal here.

Q. Okay. And you would -- would you agree with me that, to the extent, that the -- if we get into the calendar year 2018, there is no provision for the company to recover the capital investment -- the return on capital investment, of any leak-prone pipe replacement in that year?

A. The Commission will be setting rates for the rate year and the company would be free to file for rates, effective beyond this current rate year. So, if you're saying that you're limited in filing for rates, I -- I would disagree.

Q. No, I'm not saying that at all. I'm not saying we're limited in filing for rates.

I'm just asking if -- I think you agreed with my premise.

A. I'm not sure I agree with your premise.

You said there's no cost recovery beyond the rate year. That -- you’re -- you're assuming that, I mean, the company could file for rates for recovery of its expenditures and expenses.

Q. Well, let's put it this way, Mr. Rider.

How about absent the company filing for a new base-rate case, is there any way that it could recover return requirement on leak-prone pipe replacement following the expiration of the rate year?

A. Well, that's a decision that's got to be made by the company. It -- it may be earning a reasonable return and may not want to come in and file for rates. Its -- its revenues may be sufficient to cover those incremental expenses and expenditures.

Q. Okay. All things equal, if the company were not earning its allowed rate of return, the only way to recover the investment on the incremental plan, would be to file a new base rate, correct, or suffer -- or suffer the diminution of the rate return.

A. The company is free to file for rates when it believes it's necessary to -- to cover its cost of service.

Q. There is no specific mechanism, however, to recover the return requirement on leak-prone pipe replacement, that takes place after the rate year, correct?

A. Well, I -- I think we've kind of gone down a -- a -- a path here. The Gas Rates Panel proposes that there be a surcharge. I just want to be clear that -

- that that is something that staff is advocating for.

Q. Okay. Now, I -- some -- sometimes water companies have discharges, correct, to recover investment in infrastructure improvements. There's nothing like this in this case, is there?

A. The -- I -- I believe you -- the Gas Rates Panel has a surcharge proposal. I mean it -- it's a -- really a response to the company surcharge proposal. They -- they had made some recommendations in terms of how it should be calculated.

Q. Okay. I think we've beaten this horse, Mr. Rider. That’s fine.

A. Okay. If you want to ask it in the -- in -- on the next go around, that’s fine.

Q. Let's move to the -- the final issue, which is the recommendation of a penalty of 1,680,000. Do you see that?

You site to the explosion in 2004, in Pennsylvania and I believe you changed your testimony to show that the -- the joint was a buttfusion rather than electro fusion. That's correct, right?

A. I didn’t -- I don't see the word penalty. I think we used NRA and yes, on 39, we did change the word to buttfusion.

Q. You know I had to -- I went around with Mr. Stolicky yesterday.

Explain to me how you view an NRA as being different from a penalty?

A. I think the explanation is really in case 07G0141 on page 44 of the Commission Order, where the -- where the Commission basically said we have the authority to reduce rates of return, to reflect poor-service quality. We have a proven incentive programs in the context of the accepting multi-year rate plans as just and reasonable. We can index portions of the company's return for the rate year, in this case, to achieve -- to achievement of key measures of safety and service quality. Contrary to the company's claim, and the company is NFG, linkage of rates of return to fully-achievable levels of acceptable performance, is not a penalty but a lawful exercise of our authority to set just and reasonable rates.

Q. You realize the company appealed that decision, correct?

A. I am not aware of -- of that proceeding.

MS. JORGENSEN: I'm sorry. Can you repeat that question? I couldn't hear it.

MR. MILLER: I said, you realize the company appealed that decision, correct?

MS. JORGENSEN: Appealed.

Thank you.

MR. MILLER: Yes.

BY MR. MILLER: (Cont'g)

Q. So it's true, isn't it though, that the company would earn --by failing to achieve the targets imposed on it, the company would earn less than the rate of return found reasonable in the order?

A. I -- I -- I don't understand.

Q. Let's look at it a different way.

You call these NRAs, correct? The company?

A. Yes.

Q. And -- and under these NRAs, the company would have to remit some amount of dollars to some mechanism, correct?

A. Yes.

Q. And that remitting of dollars would reduce the company's earnings, correct?

A. Yes.

Q. Okay. Let's talk about the event in Pennsylvania.

Now, first question is, I believe the panel changed the testimony to concede that the -- the joint was a -- a buttfusion rather than an electrofusion, correct?

A. That's correct.

Q. Okay. And do you recall Exhibit 181, which was an answer that the staff gave to the company's interrogatory, NFG D.P.S. 177?

A. Is it an NFG IR?

Q. Yes.

UNIDENTIFIED SPEAKER: I have copies, if it will help you.

MR. RIDER: Yes, please. I don’t have that one.

BY MR. MILLER: (Cont'g.)

Q. Do you see -- I direct you to page 39 of your testimony, starting on line 14.

A. Yes.

Q. And your testimony says that there was an indication that there were workmanships concerns for distribution, right?

A. That's what it says.

Q. And you were asked about that in interrogatory 180, that's now Exhibit 181?

A. Yes.

Q. And in that interrogatory, it's true isn't it, that you concede that the relevant documents did not specifically state that investigators determined there were workmanship concerns. But then you go on to say that having a poorly aligned electrically-fused joint could be a contributing factor and could trigger workmanship concerns. Do you see that?

A. Yes.

Q. Are you familiar with the NTSB Report?

A. What N. -- NTSB Report?

Q. On the DuBois (phonetic spelling) incident.

A. We are aware that there's a report.

Q. Do you remember we were discussing Exhibit 181 and you said that a misaligned joint could trigger concerns about a workmanship issue?

MS. WOEBBE: Your Honor, may I clarify that the interrogatory response states should trigger a workmanship concerns and not could, as read by Counsel?

A.L.J. LECAKES: So clarified.

A. Which IR did you reference?

BY MR. MILLER: (Cont'g.)

Q. 177, which I believe is Exhibit 181.

A. Okay. I was confused with the exhibit number.

Can you repeat the question again then?

Q. Do you see where that IR concedes that the documents don't say that there were workmanship concerns, but then you go on to say that having a poorly-aligned electrically fused joint, be -- be a contributing factor in explosion should trigger workmanship concerns for distribution? Do you see that?

A. Yes.

Q. Are you -- and I -- and I asked you if you were familiar with the NTSB report as to the alignment of that joint.

MR. MILLER: If I can approach the witness?

A.L.J. LECAKES: Yes, you may.

A. Given --.

BY MR. MILLER: (Cont'g)

Q. Mr. Rider, doesn't that NTSB report say that there's no evidence that the joint was misaligned?

A. Is this the full report?

Q. It's a page from the report. A report that you obviously used when you wrote your testimony.

A. But there's only one page here.

So, the -- let me read the paragraph above this. It says, National Fuel began excavating the accident site before National Transportation Safety Board Investigators arrived. During the excavation, National Fuel accidently severed the plastic pipe, within a few feet of the buttfusion joint. Because of this mishap, Safety Board Investigators could not determine the undisturbed portion of the pipe to assess its bending. Only a small ligament remained connected to the buttfusion joint, remaining it -- making it impossible to directly test the strength of the joint.

Q. And what does the next sentence say?

A. Okay. The Safety Board's examination of the buttfusion joint linked to the explosion indicates that the bead widths were not uniform."

Q. Okay. Go on.

A. The bead width on one side of the buttfusion joint arranged from point 0535 inch to point 1135 inch. On the other side of the joint, the bead width ranged from point 0745 inch to point 106 inch. The total bead width ranged from point 135 inch to point 2045 inch.

The joint was found to have been visibly mitered having about a two degree angle. The

miter can concentrate stress. No evidence was found indicating that the joint was significantly misaligned.

Q. Now, when did that explosion take place?

A. (Unidentified speaker) When you say poorly aligned --.

(Rider) We say -- yeah. We said it was poorly aligned, so -- I thought there was another --.

Q. When did -- when did the Pennsylvania incident take place?

A. Per the report, it says August 21st, 2004.

Q. Right.

And the incident that you're looking for the NRA on, took place with the destructive -- you're looking for this -- NRA with respect to the company not doing destructive testing, correct?

A. Yes.

Q. And when does it appear that the company stopped doing destructive testing? Wasn't it sometime in 2011?

A. Subject to check, I believe it was 2011.

Q. So, how does destructive testing

effect an incident that took place in Pennsylvania in 2004?

(Off-the-record discussion)

A. I think I heard your question, how something in 2011 impacts something that happened in 2004.

I think what you are trying to ask is how is a plastic fusion related qualification problem in 2011 related to an incident that occurred in 2004; is that correct?

BY MR. MILLER: (Cont'g.)

Q. I'm saying that you agreed that the lack of destructive testing, seems to have taken place in 2011, correct and continued until 2014?

A. (Stolicky) I believe that's what the company filed, so yes.

Q. Well, wouldn't --

A. Between --

Q. -- that mean to you --

A. -- 2011 --

Q. -- that --

A. -- and 2014.

Q. -- so wouldn't that mean to you that jointers were being qualified using detective -- using destructive testing, prior to 2011?

A. (Rider) We didn't state that in our testimony that they were not in compliance prior to 2011.

The -- the purpose of bringing up the Pennsylvania incident was to show that the -- the importance of following procedures. Following procedures is critically important to the safety of the system and -- and not having joints that are fused properly, can -- can evolve into an incident that results in property damage and/or death and that's the purpose of bringing up the Pennsylvania incident.

BY MR. MILLER: (Cont'g.)

Q. But you -- would you agree that the Pennsylvania incident really has nothing to do with the lack of destructive testing that occurred between --

A. I -- I --

Q. -- 2011 --

A. -- I think that we're narrowly --

Q. -- and 2014?

A. -- focused on the concept of destructive testing. Destructive testing is part of properly qualifying your fusers.

What we -- what was discovered in 2004, whether NFG disagrees with the MTSB or not, there was evidence of a poorly made fusion and that's evidence

of a fully qualified fuser. Fast forward to 2011, 2014, fusers were not being properly qualified.

The qualification issue is what we're discussing here. NFG had an incident, there was question over whether someone was properly qualified and then eight years later -- seven to ten years later, there's another question over NFG not properly qualifying its fusers.

Q. You can't say, can you, that the -- that -- that the fusion made in 2004 was by someone that hadn't been qualified doing -- through among other things, destructive testing, can you?

A. If someone who is a -- who is properly operator qualified to perform a function and we're talking about fusing here, does a fusion in the field and it would fail visual inspection, which is what's described in this NTSB page, then they should not be qualified and they should be stripped of those quals. They -- therefore, they -- we're not -- they should not have been qualified that day and they would have been disqualified after making that fusion and walking away from it.

Q. You're saying people don't make mistakes?

A. I'm saying if they are properly qualified, they should be doing the job correctly, or they

will not be qualified per OQ requirements.

Q. Do you know if that -- the person that performed that fusion was properly qualified?

A. They may have been prior to that fusion, but when they made that fuse and they signed off on it and walked away, their qualifications would have been stripped due to that workmanship.

A.L.J. LECAKES: Mr. Miller, I think that the point has been made. I think you have enough to brief on this issue at this point.

BY MR. MILLER:

Q. Was National Fuel Gas subject to a NRA mechanism, for failing to meet regulations as a result of case 13-G-0136?

A. (Rider) Yes.

Q. Was -- was that provision in effect in any year prior to 2014?

A. No.

MR. MILLER: Okay. We have nothing further.

A.L.J. LECAKES: Why don’t I take a -- a five to ten-minute break before we turn it over to Mr. Mager.

(Off-the-record discussion)

Let's proceed, Mr. Mager.

MR. MAGER: Thank you.

CROSS EXAMINATION

BY MR. MAGER:

Q. Good afternoon, Panel.

Let's -- let's go through your testimony, but first I have a clarifying question around page four of your testimony. It's around -- it's the section, summary of staff's revenue requirements.

Do you see that section? It starts on three, I believe.

A. (Rider) Yes.

Q. Okay. And then towards the end of that section, you have a reference to the company's low-income program and you testify starting in the -- I'll read the whole sentence. It is important to note that in developing our recommended delivery revenue requirement, we propose to show the company's entire low-income program as a line item in the revenue requirement, rather than recover it through revenue requirement and rate design, as has been done previously.

Do you see that?

A. Yes.

Q. Can you please explain or clarify what

-- what the meaning of that -- that testimony is? Is it -- is it a substantive change in recovery, or are you talking about something more -- how it's presented?

A. We believe it's a presentation on an issue. We've -- we've tried to make this consistent for the rate cases that we've been filing testimony in. In the last few cases, for example, Keyspan, the last one I was on, the -- the problem is that when you try to recover the costs in -- in revenue allocation and rate design, it's very difficult to reconcile the program costs and we believe it's -- it's more transparent, especially since the -- the -- the commission just issued its low-income order to have the low-income program as a line item in the expense and then conduct, you know, get your revenue requirement and then design rates.

Q. Okay. So, if I'm understanding you then, it -- there's no substantive change on how it's recovered or how -- or the -- the customer class responsibilities for it. It's just more presentation in making it more transparent.

A. Yes.

Q. Okay. Thank you.

Let's go to page ten -- or actually it -- it -- it's on the capital investment plans starting

with -- the section is -- starts on page nine.

If -- if the -- if the panel will bear with me, I -- in the flurry of emails, I'm still working off of your original testimony, so my -- my pages and lines might be slightly different from your -- the minimally corrected one.

But you -- you testify that the capital investment budgets -- I believe it's on page ten, for the year ending September 30, '14 and the year ending September 30, '15, were 48.2 million dollars. Are you with me?

A. We believe that's on page 10, line 21.

Q. Yes.

Okay. And then above that you're looking at a -- a budget -- a comparable budget for the period 9/30/17 of 77.2 million, declining slightly for the year -- declining to 72.3 million in the year ending September 30, '18?

A. Yes. Line 8 and line 10.

Q. Okay. And so right now, it -- you look -- you're looking -- or customers are looking at a -- a -- roughly a 50% percent increase from fiscal year '15 to fiscal year '17?

A. Are you -- you're saying from 48.2

million to 77.2 million?

Q. Yes. Is -- okay.

A. The difference is 29 million?

Q. Yes.

A. Over 48.2 million.

Q. Yes.

A. Yeah. I got 60 percent.

Q. Okay. So it's -- it's comfortably above a 50% increase over the -- from the -- for the -- over the two year period?

A. Yeah. I got 60%.

Q. Okay. Thank you.

Would it be fair to say that a portion of that 60% increase -- approximate 60% increase relates to the accelerated replacement of leak-prone pipe, which is a Commission goal?

A. Yes.

Q. Could you -- would it be fair to say that a significant portion of that increase relates to leak-prone pipe replacement?

A. To be honest, I think really these questions should be directed to the Gas Rates Panel. We reviewed -- that panel reviewed the capital expenditure budgets. This is really just to give a high level

overview of the spending related -- you know, where the company plans to go.

Q. Okay.

A. So if you have detailed questions, really that's --

Q. The --.

A. -- the panel to ask.

Q. Yeah. This was actually as detailed as I was getting, so -- but I -- I'm -- I'm okay. I don't want -- I don't want the panel to --

A. Okay.

Q. -- go beyond its comfort level.

Let's -- let's move ahead to page -- I have it as 17, where you're discussing what I believe you're calling the framework order in the Reforming the Energy Vision proceeding.

A. Yes.

Q. Okay. Would -- would you agree with me that that -- the REV order is primarily applicable to electric utilities?

A. Yes.

Q. Okay. Now is it my understanding that you are proposing certain financial incentives in this case, in an effort to be somewhat generally consistent,

with that order?

A. Yes.

Q. Okay. But you're not interpreting that order as -- as mandating it, or requiring specific incentives in this case?

A. No.

Q. And -- and in fact, that order doesn't -- doesn't mandate the implementation of any new gas -- new incentives for gas utilities, like it does for electric utilities?

A. I think that order speaks for itself.

Q. Okay. I'll accept that.

Now, if we could turn to page 21 and we start discussing the incentive mechanisms -- renewing incentive mechanisms being proposed. I believe that's the key, where you list nine new positive incentive mechanisms being proposed on page -- I think it's page 21.

A. Yeah.

We have a list of -- of the incentive mechanisms.

Q. Right.

And the list is nine; right? Nine new ones?

A. Yeah.

So --

Q. I --.

A. -- although, you know, as -- as we discovered the residential methane detection really didn't have an incentive tied to it at this point in time.

Q. Yeah. We're -- I -- I think we're going to get into this -- the status of those proposals, but -- now these positive incentives, these -- these would be in additional to certain incentives that already exist, where the company can earn additional funds and for example, the existing LAUF incentive as well as the sharing of transportation revenues, currently are symmetrical incentives that are in effect now, correct?

A. I believe that's in our testimony. I'm just trying to find --.

Q. It's a few pages prior to where I directed you previously.

A. Right. In the summary of rate mechanism, loss --.

Q. I don't intend to go into detail on them. I just -- basically there's a -- there already exists a symmetrical incentive for -- for the LAUF; correct?

A. Yes. Albeit, it's somewhat tempered

now that we have a dead band around the -- the fix factor.

Q. Okay. And there's a symmetrical incentive with respect to transportation revenues?

A. Yes.

Q. Okay. Now, I just want to make sure that record is clear in terms of potential basis points of positive incentives, I -- I calculated 44 and if I can quickly go through it -- will you accept 44?

A. Yes.

Q. Is that the same -- okay.

A. Plus, there's the -- two other opportunities --

Q. Okay.

A. -- that -- that we had previously mentioned.

Q. Right.

And I -- and -- and so I have 44 from six of the mechanisms and I understand there's no dollars attached to the gathering system odorization and the NGV incentive. Do you agree?

A. Yes.

Q. Okay. Now, with the residential methane detection, there is testimony in there about a 148 thousand dollars. I wasn't -- is that -- is that properly

viewed as a potential incentive?

A. It's not an incentive.

Q. Okay. What is that then?

A. (Davi) That's what -- that's what the Gas Safety Panel testified to as with the company of -- as an NRA with non-compliance with the pipeline safety regulations for calendar year 2014.

Q. Okay. So instead of -- instead of that NRA being assessed against the company, they'd be allowed to offset some expense with it? Isn't that somewhat akin to financial incentive, or no? Am I misinterpreting it?

A. (Rider) We believe this NRA should be used to offset the costs associated with the deployment of the residential methane detectors.

Q. Okay. So, let's -- let's put that aside then. The -- the 44 potential basis points, I -- I calculate, or understand to be approximately 2.2 million dollars; is that -- is that accurate, using your figures?

A. Yes. That's accurate.

Q. Thank you.

Now, the first -- the first new proposal you recommend deals with terminations and uncollectibles for residential customers; correct?

A. Yes.

Q. And if the company earns that positive incentive, would it be collected only from residential customers?

A. (Ferrefi) No.

(Rider) No.

Q. It would be collected from all customers?

A. Yes.

Q. Currently uncollectables are treated differently, right, for residential and nonresidential customers?

A. (Davi) Mr. Mager, I am not aware of it being in a separate --.

Q. Okay.

A. Could you point us to where that is?

Q. Offhand, no, but my understanding is they are separate --.

A. It’s my understanding --

Q. It’s -- they’re --

A. -- that when --.

Q. -- separately tracked and there are separate figures on uncollectable allowances for residential and nonresidential.

A. I thought that you were indicating the rate allowance. When the rate allowance was set in the last refiling, it was based on a net write-off factor, and there was one net write-off factor.

Q. Okay.

A. I don't believe there was one for residential and another one for nonresidential, so that's -- that's my understanding.

Q. Okay. Let's leave it at that for now.

A. Okay.

Q. Your -- your next proposal involves an incentive for lowering unit costs and is it -- is it fair to say that this is not fully fleshed out?

A. (Rider) Yes.

Q. And is it fair to say also that based on the -- the record as it stands today, there's nothing specific for the Commission to rule on with respect to this incentive mechanism?

A. I believe the Commission could rule that it wants this mechanism to go forward and have some type of --

Q. When you say --

A. -- collaborative effort to --

Q. -- this mechanism --.

A. -- to set the targets which the utility would be measured on in the right year.

Q. When -- when you say this mechanism, what -- we don't have a mechanism, is there?

A. The -- the mechanism is the proposed lowing of unit costs mechanism.

Q. So, let -- let me take a back -- take a step back.

There's no specific proposal that you can point to that the Commission could -- could say is approved and goes into effect?

A. It -- there's not a package deal here, no.

Q. Okay.

A. There -- there needs to be components that are worked out so that the utility understands what its goals are and that -- you know, customers are understand -- I guess, what their financial -- I guess payment would be for -- for the utility achieving those goals.

Q. Let me ask you similar questions.

There's no fully fleshed-out proposal for resident -- residential methane detection, correct?

A. No. We propose that the NRA for 2014

be used to offset the costs of the residential methane detector deployment.

Q. Is that -- is that a specific -- do you consider that a fully fleshed out proposal?

A. We're asking for a plan for the -- from the company.

Q. Right. And are you also -- would it be fair to say that the gathering system odorization is not a fully fleshed out proposal?

A. Yes.

Q. Would it be fair to say that the NGV incentive is not a fully fleshed out proposal?

A. Yes.

Q. Now, in the REV case when the Commission -- in the framework order when the Commission was discussing incentive mechanisms, wasn't it in the context of deciding that within rate cases?

A. I don't have the REV order in front of me. Could you provide that and cite to where that's stated?

Q. No. I'm just -- I'm just asking for your understanding.

Is -- is -- is your -- is that the reason you presented these proposals, for -- for purposes

of this rate case in -- was it your understanding the intention was to address incentive mechanisms within the context of a rate proceeding?

MS. WOEBBE: Your Honor, these witnesses don't speak for the Commission or what the Commission intended to do.

A.L.J. LECAKES: Right.

But I don't think Mr. Mager's question is going to a legal conclusion. I think he's asking staff in their capacity as enacting Commission orders -- particularly in this case, REV, is it their understanding that they're supposed to pursue these mechanisms in rate proceedings and if that's true, is that why they've proposed -- made these proposals, such as they are in the testimony right now.

Is that correct, Mr. Mager?

MR. MAGER: Yes, your Honor.

A. That's my recollection.

BY MR. MAGER: (Cont'g.)

Q. And so to the extent these proposals would be subject to litigation and cross-examination, now would be the only time that could happen, correct?

A. I think the commission can adopt a concept and I think that the details can be worked out in

some other form.

Q. Well, yeah. You testified that staff would like to work with the company on designing this incentive, but if there are intervener parties who don't like it, isn't -- isn't now our opportunity to cross-examine it?

A. Any -- I think anything the Commission does is subject to -- to all parties being involved. I don't -- I don't -- I -- I don't know one case that the -- the Commission excludes parties from participating. So it would be my proposal that if the Commission adopts this concept, but we need to work out some of the details, that all parties could participate and to the extent that those parties do not like the outcome of the majority of the parties conclusions there, that, you know, they -- we could set up a process where that filing could be SAPA'd and there could be comments, and the Commission could ultimately rule on, you know, the -- the targets.

MR. MAGER: Your Honor, I -- I guess I -- I'm trying to formulate in my mind a motion to make on this.

I -- I -- I think asking that certain testimony be striked in this instance would be too extreme and I'm not necessarily seeking that. On the other hand,

I'm not sure what parties are supposed to do in terms of briefs and this is -- this is the litigated case. This is the rate proceeding and we have at least three if not four proposed incentive mechanisms that are, in my words, not ready for primetime, that are still -- need to be formulated and so I don't -- I -- I don't know what I am shooting at if I don't like them.

A.L.J. LECAKES: I completely appreciate the point that you're trying to make and I also appreciate the fact that you're not making a motion to strike because I -- I would deny it at this point, but I do think that your questions has elicited answers that are sufficient to brief on -- on the lack of -- of meat around the bones shall we say and I think we'll leave it at that right now.

MR. MAGER: Okay. Thank you, your Honor.

BY MR. MAGER: (Cont'g.)

Q. Can you turn to -- let's -- let's -- let's briefly discuss your lowering unit cost concept.

Now, am I correct that you believe that this incentive concept is needed because while the company has a strong incentive to control capital expenditures, it does not have the same -- does not have

the same -- withdrawn.

It -- am I correct that staff believes this concept is needed because the company has a strong incentive to control operating expenses, but not necessarily capital expenditures?

A. Because of the net plant true up, that's a weakness of the net plan true up. That the company may not have as strong as an incentive to control capital expenditures.

Q. And on page twenty-three, you -- you have a quote from line ten in my copy, so it's probably a few lines off in yours. The company may manage the investment plans to the targets and make investments of higher levels to avoid a deferral for customers. Do you see that?

A. Yes.

Q. Do you -- do -- do you have evidence that the company has done that?

A. I have no evidence that the company has done that.

Q. Okay. Now, turning -- I believe it's on the next page -- there's a question and your -- your response is one option is to develop specific unit cost tractors for budgets that have specific benchmark costs

and deliverables, such as miles of main, numbers of services or number of meters. Do you see that?

A. Yes.

Q. Wouldn't an incentive like -- wouldn't a mechanism like that provide an incentive for the company to increase its budgets?

A. If you look at the next page, on page twenty-five --

Q. Uh-huh.

A. -- line eleven, we stated careful consideration should be given so that incentives are not the result of poor estimation, but actual innovation and cost control.

Q. Okay. So, if they are -- so, when they're laying miles of main and they tell you how many -- how many miles of main that they -- they installed and what it cost them, are -- are you able to identify what innovation they used?

A. No. That's in the company's court.

Q. Right. So -- so -- so staff is not capable of identifying whether -- whether the incentives are the result of poor -- poor estimation or actual innovation and cost control?

A. We -- we -- we have historic data that

track unit costs for the company and that's why we're stating that we believe using trackers with specific benchmark costs and deliverables, will give us that -- that reference point to measure future unit cost reductions.

Q. Will the unit costs for doing various tasks stay the same from year to year?

A. That's a pretty broad question.

Q. Okay. Well --.

A. What I would say is that we would measure this type of incentive, based on the aggregate program, so that one or two jobs wouldn't skew the average. It would have to be in total.

Q. Well, if you -- if you separate the specific targets by categories, would -- would that impede the company's ability to move money around from different projects based on priorities changing?

A. The way we envision the -- the mechanism working would be that the utility would file it's leak-prone pipe prior to authorization schedule with us so that we would know and under -- know and understand the top priorities the company has and then a year later, when we actually look at the -- the actual performance, we would ensure that the company stuck to its priorities and

then didn't move the money around just to -- to reduce the unit costs.

Q. Right.

And so if -- when the company files its planned -- when the -- when the company files its planned replacements with a -- a -- a estimated cost, wouldn't creation of this incentive mechanism give them an added incentive to overstate the projected costs?

Wouldn't it be in their financial interest to do so, so that they can come in under budget and earn an incentive?

A. I mean, I can't speak to the -- to the company's actual -- if -- if -- if -- if they would actually have nefarious intentions on padding budgets, but I think in -- when developing these unit costs, we would look at historic actual achievements, along with the -- the contracts that they have with their contractors, to determine whether those unit costs are reasonable or not.

Q. Well, you say you don't want to impugn the company with nefarious thoughts, but then aren't you doing that when you say that they may manage the investment plans to targets and make investments of higher levels to avoid a deferral for customers? Isn't that a -- the exact same thing?

A. I have no evidence that they do that, but in the rate -- in -- when we develop rates, we review the company's capital plan to determine which -- if -- if -- if it's reasonable and we set delivery rates that customers pay. If the utility does not deliver its capital investment plans, we do not believe it's fair that customers should pay a rate of return for those investments that are not made.

Q. Now, with the -- let's shift gears a little bit.

The leak-prone pipe incentive proposal, am I correct that the incentive would involve not only up to an additional ten basis points, but the company would get to recover all the additional expense associated with it -- with achieving that -- that goal?

A. Expense?

Q. And I --.

A. Where -- where do you see -- see expense?

Q. You know what?

A. I'm just not --.

Q. I, you know, I might have referred to it as leak management. I -- I should have said leak-prone pipe mileage.

At -- at the end of the section on additional leak-prone pipe mileage, page 26 on my version, maybe of the bottom of page 25 on yours, it says that the costs of the additional mileage and this incentive will be recovered in the company's proposed surcharge mechanism. Can you -- do you see that?

A. Yes.

Q. So, if I understand it, we talked earlier about how the cap-ex budget has gone up 60% in the last two years, part of that is to -- is to achieve increased leak-prone pipe replacement and then this incentive would pay the company basis points for achieving more plus they would also recover all the additional costs of the add -- of achieving the additional mileage? Is that -- is that correct?

A. Base rates will allow the recovery of the mileage targets that we've proposed. To the extent that the utility replaces mileage above those targets, they would -- there would be allowed recovery in this surcharge for the -- that incremental mileage.

Q. Okay. So -- so they -- the increase costs of achieving additional mileage, plus the incentive would be recovered from customers?

A. The actual costs of achieving the

additional mileage, plus the incentive.

Q. Okay. And so I wonder if the additional mileage costs more than on -- on a unit basis.

A. Well, the Gas Rates Panel had proposed unit-costs caps.

Q. Okay. Is that -- is that part of your proposal here?

A. The Gas Rates Panel proposed unit-cost caps.

Q. Okay. Let's -- let's turn quickly to the damage prevention incentive. I believe it's around page 30. Just let me know when you're there.

A. I'm there.

Q. Right.

My -- my understanding is this incentive will provide positive -- this mechanism would provide positive incentives to the company if it can achieve fewer than 1.5 damages per 1000 one call tickets?

A. Yes.

Q. And where is the company now on that roughly?

A. (Stolicky) Again, in 2015 there were at 2.20.

Q. Okay. Now, this -- you testified in

support of this that public safety should be of the utmost importance. Do you see that in this next to last answer in this section? I'm sorry. It's kind of in the middle of the sentence.

The question is, why is this level of performance reasonable and one of the -- one of the responses -- part of the response says public safety should be of the utmost importance. Do you see that?

A. (Rider) Yes.

Q. Now does this mechanism include a panel fee if the company's performance gets worse?

A. (Stolicky) Those targets are covered in the Gas Safety Panel and the simple answer is yes. If they go backwards from 2.2, based on proposed targets, there would be an NRA.

Q. Okay. Now, for some of these proposals that are still being developed, in terms of the details, I want to refer back to the framework order that -- that we discussed earlier in the REV proceeding.

In addition to positive incentives, do you recall the order's discussion about score-card metrics? Are you familiar with that term as it's used in REV?

Would you like me to point it for you

in general concept?

A. (Rider) Yes, please.

Q. Okay. Didn't -- weren't there a number of metrics that the Commission wanted to keep track of, without putting specific dollars attached to them to start following performance -- start measuring performance and then the -- some of those may in the future become incentives?

A. I'd have to look back at the REV --

Q. Okay.

A. -- Order to --.

Q. All right. If you're not familiar, we can move on.

MR. MAGER: If I could just have a minute, your Honor, I think I might be done.

A.L.J. LECAKES: Absolutely.

MR. MAGER: I -- I -- actually, I just have one last -- one last line for the company -- the panel.

BY MR. MAGER: (Cont'g.)

Q. Is it -- is it your position that incentives can either be positive, negative or symmetrical?

A. Yes.

Q. And in fact, that's kind of what you're proposing in this case? A -- a number of incentives that are either positive, or negative, or symmetrical?

A. Yes.

Q. And would it be fair to say that you're trying to -- is -- is the panel trying to reach some type of balance between potentially positive incentives and potentially negative incentives and symmetrical incentives?

A. (Sano) Counsel, I think it depends on what type of incentive -- or what the situation is behind the incentive.

As an example, with the infrastructure enhancement program that measures the amount of growth in customers, we didn't include a downside to that because we think a company doesn't have any control over a -- a -- a -- a potential customer saying no, where we do think they have the capability to entice somebody to say yes, either it be through rebates or contribution to the line extension, or whatever the case may be. So you won't see a negative one there. But when we set the forecast with the -- the -- through the rate case, we're assuming that if they don't meet it, that in itself is a detriment.

Okay. So you may not see a positive and a negative together and so you could have some that is symmetrical, some that are a positive and some that are a negative. We think it depends on the individual situation behind what the goal is with each one.

Q. Okay. So you're not -- you're not striving to reach some sort of particular balance, in terms of how -- money's available positively, money's available negatively?

A. I -- I think you'll find that with just about every incentive that we suggested, or requested, or proposed, that there's a goal in mind and we're trying to help the company reach that goal.

MR. MAGER: Okay. Thank you.

I -- I have nothing further, your Honor.

MR. SANO: Okay.

A.L.J. LECAKES: Thank you.

Is there any other party that has cross? I don't have any indicated.

A.L.J. LECAKES: Panel, the one issue that remains to me after the extensive cross from the company and from Mr. Mager, concerns this -- this issue that Mr. Mager first addressed in his cross-examination

with the -- the comparison of the revenue-requirement documents and I know it's not a huge issue substantively, but it concerns me as someone who has to write a recommendation to the Commission.

When -- when we look at this presentation issue, is there any way that I can have a side-by-side through exhibits that you're aware of have been entered in this case, a side-by-side comparison that would show me what has been recommended and -- and the costs associated with it by the company at the beginning of the case, through its rebuttal case, as -- as, you know, against staff's recommended revenue requirements? I mean, is there any comparison documents that I have available to me in the exhibits that you're aware of where I could do side by side comparisons like that?

MR. FAVREAU: I believe, your Honor, we've asked that of the company, at least on rebuttal. I -- I believe what we got was -- was not what is normally done in a rate case.

MR. MILLER: I -- I disagree and we've had this discussion. And -- and for National Fuel, at least, I can say -- and we talked about this at the settlement conference, what we've done in the past with staff is we prepare a document for your Honor, that

lists the company filing and all the steps along the way. Staff case, company's rebuttal case and things that are agreed upon and the issues that are live and the dollar values that they have for your Honor.

So you have a menu when you go down and look at that exhibit -- we -- we -- we've done it in the past, Mr. Miles confirming it, you can say okay, here's an issue -- productivity, right? One percent, two percent, no productivity adjustment. It's worth this much money, what it applies to. It's -- it's an expense item. You go down through that list, you'll see all of those things.

I think we've heard in the reply brief because there may be concessions in the initial brief, but that's always been the -- the practice and it's our intention to do it in this case.

A.L.J. LECAKES: In -- in the briefing phase?

MR. MILLER: In the briefing phase because there are things that -- also things that come up in the briefing phase, but you would have a cost of service that would show you the contested issues, the settled issues, what they're worth and you could just check them off and -- as you're going through your

decision on each contested issue or -- and you'd have a final revenue requirement, you'll see what issues were settled, were agreed on, things like that.

A.L.J. LECAKES: I --.

MR. FAVREAU: I -- I just ask one question, your Honor.

A.L.J. LECAKES: Go ahead.

MR. FAVREAU: If that is in a reply brief, is that the kind of a consensus document?

MR. MILLER: Yeah.

MR. FAVREAU: I mean, I don't --

MR. MILLER: Yeah. Yeah. We work together.

MR. FAVREAU: So, that would be shared with the parties?

MR. MILLER: Yeah.

A.L.J. LECAKES: Okay. That was my question.

My other question however, is to the extent that that process works and -- and so far it sound like I can work with it, will there be -- will there be sufficient citations within either the replied brief itself, or in that exhibit, that I can trace it directly to exhibits that are in the record

-- or I mean -- I mean that attachment to the reply brief?

MR. MILLER: That's always been our intention to write briefs with precise citations.

Mr. Mainl is here. He's done this before. He can address how it's worked in the past.

MR. MAINL: I believe that's how it was done in the 2007 case. We worked with staff, as far as what issues were still in contention and identified those issues and have a revenue requirement established that show again, where the parties were disagreeing and from that, you could determine what the value of -- of each disagreement is.

A.L.J. LECAKES: Mr. Mainl, that's -- that's great.

Can you get me between -- if you get the opportunity between tonight and tomorrow, say like noon, for our lunch break or whenever it is, a copy of the 2007 one, just so I can see what you're talking about?

MR. MAINL: Yes.

A.L.J. LECAKES: Thank you very much.

Staff, do you want to approach the

panel and -- and discuss redirect?

Why don't we go off the record and we'll give them a few minutes, so if you want to get up and stretch, feel free to. That was pretty extensive cross so --.

(Off-the-record discussion)

A.L.J. LECAKES: Direct?

MR. MAINL: Yeah. Very limited.

MS. WEOBBE: One quick question, your Honor.

REDIRECT EXAMINATION

BY MS. WEOBBE:

Q. Staff, please direct your attention to page 39, where you discuss safety-violations' metric.

Does staff apply to safety-violations' metric to calculate NRA?

A. (Rider) No.

We did not specifically apply any violation to come up with the -- the NRA. What we -- what we did is we used it as a proxy to come up with a reasonable approach to calculate the NRA.

MS. WOEBBE: That's all, your Honor.

A.L.J. LECAKES: I -- I -- I don't think that clarifies anything. I think it confuses

things.

Can -- can you, Mr. Rider, can you please elaborate on that?

MR. RIDER: Sure.

I -- I -- I didn't want to have the impression that -- that there was -- the -- the gas safety-violations' metric was in place after the 2013 case and it was -- it's very specific to the sections of the code that the company must comply with. And it's true that the -- while -- while plastic fusion is -- is -- would be a part of that, we're not saying that it -- it's appropriate to, you know, utilize this gas-safety violations' metrics for that period of time. I was using it as a proxy to come up with a value what is an appropriate NRA for this period of time. And -- and I use that gas-safety violations' metric as found in the 2013 order, where it stated that, you know, for every occurrence from one to fifteen, was worth half a basis point to come up with a reasonable approach.

A.L.J. LECAKES: Okay. I -- I think I understand what you're saying, but I don't think that may necessarily eliminate some re-cross that the company might have on this point.

Mr. Miller?

MR. MILLER: I think I'm okay with that.

A.L.J. LECAKES: Okay. All right. This panel is dismissed, except for Mr. Sano. You remain under oath.

Let's go off the record real brief.

(Off-the-record discussion)

A.L.J. LECAKES: Let's go back on the record.

Staff, please call your next witness or panel.

MS. AISSI: Your Honor, Staff calls its Gas Policy and Compliance Panel.

A.L.J. LECAKES: Thank you.

Mr. Weeble, Mr. Miorello, can you please identify yourselves by name and business address for the record?

MR. WEEBLE: Yes, your Honor.

Andrew Weeble. My business address is 3 Empire State Plaza, Albany, New York 12223.

MR. MIORELLO: Dave Miorello. My address is 3 Empire State Plaza, Albany, New York 1220 -- 2223.

A.L.J. LECAKES: Okay. Mr. Sano is already on the record. Could the two of you please stand up, raise your right hand? Do you swear or affirm that the testimony you're about to give today is the whole truth?

MR. WEEBLE: Yes.

ANDREW WEEBLE; Sworn

MR. MIORELLO: Yes.

DAVE MIORELLO; Sworn

A.L.J. LECAKES: Okay. Please sit. Now Staff. go ahead and proceed.

DIRECT EXAMINATION

BY MS. AISSI:

Q. Members of the Panel, has the pre-filed testimony for this case been prepared by you or under your supervision?

A. Yes, it has.

Q. Is the 51 page document in front of you that testimony?

A. Yes, it is.

Q. Do you wish to make any changes to that testimony?

A. No. We have no changes at this time.

Q. If I were to ask you today the same

questions that are in your prepared testimony, would your answers be the same?

A. Yes, it would.

MS. AISSI: Your Honor, I ask that the Panel's testimony be incorporated into the record, as if given orally today.

A.L.J. LECAKES: Granted.

At this point the transcript should insert on the Staff Testimony disk, the file called GPS Panel Testimony.

Insert testimony of GPS Panel.

BEFORE THE
STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

In the Matter of

National Fuel Gas Distribution Corp.

Cases 16-G-0257

August 2016

Prepared Testimony of:

Staff Gas Policy & Supply Panel

John P. Sano
Utility Supervisor

Andrew Riebel
Utility Engineer 3

Davide Maioriello
Utility Engineer 3

Office of Electric, Gas, and Water
State of New York
Department of Public Service
Three Empire State Plaza
Albany, New York 12223-1350

INTRODUCTION AND QUALIFICATIONS

Q. Members of the Staff Gas Policy and Supply Panel (Panel), please state your names, employer and business address.

A. Our names are John Sano, Andrew Riebel and Davide Maioriello. We are employed by the New York State Department of Public Service (Department) and our business address is Three Empire State Plaza, Albany, New York 12223-1350.

Q. Mr. Sano, what is your position in the Department?

A. I am a Utility Supervisor assigned to the Gas Policy and Supply Section of the Office of Electric, Gas and Water of the New York State Department of Public Service.

Q. Please summarize your education and professional experience and any honors you have received.

A. I completed my Bachelor of Science degree in Chemical Engineering at Clarkson University in 1974. In 1974, I was inducted into Phalanx the Clarkson Honorary Society for outstanding achievements as an undergraduate. I also completed my Masters in Business Administration at the State University of New York at Albany in

1983. Prior to the start of my employment with the Department in 1990, I held several engineering and management positions with the Union Carbide Corporation at its Bound Brook, New Jersey Phenolic Plastics Division from 1974 through 1976 and with the General Electric Corporation at its Silicone Products Division in Waterford, New York from 1976 through 1990. My responsibilities at various times included new process development, process engineering, production engineering, production management, customer technical support, project management and maintenance management. During my tenure at General Electric, I was a Bronze Medallion Award recipient. This award acknowledges individual contribution as an author of Company patents and trade secrets. Since joining the Department in 1990, I have held various engineering and supervisory positions in the former Gas Division, as well as the former Energy & Water Division.

Q. Please describe your duties in the Office of Electric, Gas and Water.

A. The majority of my responsibilities include

analysis of natural gas utility policy matters, including distribution system design and planning, capacity asset management, gas purchasing practices, and gas system reliability, as well as analysis of issues related to the restructuring of the natural gas industry and use of natural gas in New York.

Q. Have you previously testified before the Public Service Commission (Commission)?

A. I have testified in various proceedings before this Commission. These proceedings include rate cases 14-G-0319, Central Hudson Gas and Electric Corporation (CHG&E); 90-G-1001, Consolidated Edison Company of New York, Inc. (CECONY); 90-G-0649, Rochester Gas and Electric Corporation (RG&E); 04-G-1047 and 07-G-0141, National Fuel Gas Distribution (Distribution or the Company); 06-G-1185 and 16-G-0059, The Brooklyn Union Gas Company d/b/a KeySpan Energy Delivery New York (KEDNY); 06-G-1186 and 16-G-0058, KeySpan Energy Delivery Long Island, now d/b/a National Grid (KEDLI); 08-G-1392, St. Lawrence Natural Gas, (St. Lawrence); and, 02-G-0003 and 05-G-1359, Corning Natural Gas.

Q. Mr. Riebel, what is your position in the Department?

A. I am a Utility Engineer 3 assigned to the Gas Policy and Supply Section of the Office of Electric, Gas and Water of the New York State Department of Public Service.

Q. Please briefly describe your educational background and professional experience.

A. I am a graduate of Syracuse University with a Bachelor Degree in Mechanical Engineering. I joined the Department in October 1990, and have worked as an engineer in various sections of the Department since that time. My experience has been in the areas of Gas Rates, Energy Resources and the Environment, Retail Market Development and currently in Gas Policy and Supply section. This exposure to different fields of utility regulation has provided me with a broad knowledge of the utility industry.

Q. Please describe your duties in the Office of Electric, Gas and Water.

A. The majority of my duties have been focused in performing various engineering analyses of gas capacity and supply planning, projects and

1 associated capital budgets, operation and
2 maintenance (O&M) expenses and programs, and
3 review of various petitions and tariff filings
4 of gas and electric utility companies in New
5 York State.
6 Q. Have you previously testified before the
7 Commission?
8 A. Yes. I have previously testified in Cases
9 15-G-0382, St. Lawrence Gas Company, Inc., and
10 most recently in 16-G-0061, Consolidated Edison
11 Company of New York, Inc.
12 Q. Mr. Maioriello, what is your position in the
13 Department?
14 A. I am a Utility Engineer 3 assigned to the Gas
15 Policy and Supply Section of the Office of
16 Electric, Gas and Water of the New York State
17 Department of Public Service.
18 Q. Please briefly describe your educational
19 background and professional experience.
20 A. I attended Hudson Valley Community College and
21 graduated with an Associate in Applied Science
22 degree in construction technology. I continued
23 my education at the SUNY Institute of Technology
24 and in May 1999 graduated with a Bachelor of

1 Science degree in civil engineering technology.
2 From February 2000 to February 2003, I was
3 employed by SPEC Consulting, LLC as a Project
4 Engineer. My work involved project management
5 and coordination, engineering, as well as
6 various computer aided design projects, for
7 several clients. From February 2003 to December
8 2005, I worked for the City of Albany
9 Engineering Division, where I was responsible
10 for a number of tasks which included inspections
11 of major roadway projects and other municipal
12 construction projects. I was also engaged in
13 permit processing and utility work inspections.
14 In December 2005, I joined the Department.
15 Q. Please describe your duties in the Office of
16 Electric, Gas and Water.
17 A. The majority of my duties have been focused in
18 performing various engineering analyses of gas
19 capacity and supply planning, projects and
20 associated capital budgets, O&M expenses and
21 programs, and review of various petitions and
22 tariff filings of gas and electric utility
23 companies in New York State.
24 Q. Have you previously testified before the

1 Commission?
2 A. Yes. I have previously testified with respect
3 to capital expenditures, materials and supplies,
4 depreciation rates, sales forecasting, revenue
5 decoupling mechanisms, revenue allocation, rate
6 design, lost and unaccounted for gas, capital
7 expenditure reconciliation mechanisms, retail
8 access issues, reliability forecasting & supply
9 planning, peaking supply and capacity issues,
10 design day & winter forecasting, reliability
11 improvements, gas infrastructure enhancement and
12 reporting requirements. I have testified in
13 Cases 05-G-1494, Orange and Rockland Utilities,
14 Inc. (O&R); 05-G-1635, St. Lawrence Gas Company,
15 Inc. (St. Lawrence); 06-G-1185, Keyspan Energy
16 Delivery New York (KEDNY); 06-G-1186, Keyspan
17 Energy Delivery Long Island (KEDLI); 07-G-0141,
18 National Fuel Gas Distribution Corp.
19 (Distribution or the Company); 08-G-0609,
20 Niagara Mohawk Power Corporation d/b/a National
21 Grid (NMPC); 08-G-1392, St. Lawrence; 09-G-0716,
22 New York State Electric & Gas (NYSEG); 09-G-
23 0718, Rochester Gas & Electric (RG&E); 11-G-
24 0142, Chautauqua Utilities, Inc.; 12-G-0202

NMPC; 12-E-0201 NMPC; 14-G-0319, Central Hudson Gas & Electric (CHG&E); 14-G-0494, O&R; 15-G-0382, St. Lawrence; 16-G-0058, KEDLI; and 16-G-0059, KEDNY.

SUMMARY OF THE TESTIMONY

Q. What is the purpose of the Panel's testimony in this proceeding?

A. Our testimony will discuss the following gas areas:

- Distribution Infrastructure Enhancement
  - Customer Conversion Efforts
  - Gas Enhancement Performance Incentive
  - Prime Western NY Program
  - Distributed Generation (DG) and Natural Gas Vehicle (NGV) Programs
- Local Production/Renewable Gas Source Issues
- Indigenous and Renewable Gas Supplies (RNG)
- Workforce Development Programs
- Review of Research, Development and Demonstration Programs
- Electric Generation Issues
- Transportation and Balancing Procedures and Charges

Q. Is the Panel presenting any exhibits?

A. Yes, we are sponsoring one exhibit, labeled Exhibit__(GPS-1), which contains responses to Staff interrogatories (IRs) that are relevant to the scope of our testimony.

DISTRIBUTION INFRASTRUCTURE ENHANCEMENT

Q. What is meant by Distribution Infrastructure Enhancements?

A. In the past, the Department and Commission referred to these activities as natural gas expansion efforts, for example in Case 12-G-0297, Proceeding on Motion of the Commission to Examine Policies Regarding the Expansion of Natural Gas Service, (issued November 30, 2012). However, more recently the Department and Commission have referred to these efforts as Natural Gas Infrastructure Enhancements to better reflect these project applications as encompassing more than customer additions. These activities include adding new customers both along existing infrastructure and extending that infrastructure to reach new customers, putting in new Transmission & Distribution (T&D) plant, extending service to non-heating customers, including improvements to existing

infrastructure to support ongoing system safety and reliability. These efforts are designed to improve the efficiency, safety and effectiveness of every dollar spent on the distribution infrastructure.

Q. With respect to Gas Infrastructure Enhancements, what does the Panel intend to address?

A. We will address the Company's existing programs, our recommended changes to the programs based on the existing pilot program results, financing and customer incentives for the programs, the Company's Area Development, Prime Western NY program and Natural Gas Vehicle Program.

CUSTOMER CONVERSION EFFORTS

Q. Please describe the Company's existing program on Gas Infrastructure Enhancement.

A. The Company has developed a program which details how it is going to help provide natural gas service to more residences and businesses within its service territory. As a result of the most recent rate proceeding, 13-G-0136, the Company provides an annual report on its gas Infrastructure Enhancement activity to date along with what is projected. The plan includes

implementing a Geographical Information System (GIS) program to identify unserved areas, supporting conversion of low income customers to gas service, growing its NGV program and initiating pilot programs within its service territory to identify approaches that will successfully assist conversions from alternate fuels. The Company targets non-customers including those that are within 100 feet of an existing distribution main and those that are beyond 100 feet. It also targets existing customers who do not use natural gas for space heating.

Q. What activity has taken place to date?

A. The Company has started two pilot programs for line extensions, one in the Town of Wilson and another in the Town of Richmond. For the Wilson pilot, the Company determined that a combination of a maximum $30 monthly surcharge and a limit of an $1,800 pre-payment for costs in aid of construction (CIACs) from the customer yielded the best results for encouraging customers to switch to gas. For the Richmond pilot, the Company was able to adjust the monthly surcharge

level to $13 per month and a limit of an $800 pre-payment.

The Company Report on the New York State Electric and Gas Supply Readiness for the 2016-2017 Winter, regarding pilot program status, filed in Case 16-M-0263, identified that within the first two years of the line extension pilots, 123 of the potential 228 customers applied for gas service in Wilson, while 329 of the potential 585 customers applied in Richmond. This represents a planned conversion rate of approximately 43% and 56%, respectively. The Wilson Pilot has converted 75 customers to date, and the Richmond pilot has converted 47 customers. The target goal for conversions in these line extension pilot projects, within 10 years of line installation, was set at 75% of potential customers. The Company's Report also shows that, starting in 2016, it has begun to convert some of its Phase II pilot customers. As of June 2016, the Company has converted 36 of the 284 potential Phase II customers. Applications received in Phase II total 140, which equates to approximately 49% of potential

1 customers.
2 Q. What does the Company project for the future of
3 its pilot programs?
4 A. As shown in the June 1, 2016 update on its Gas
5 Infrastructure Enhancement Program, as well as
6 the 16-M-0263 filing, the Company discusses
7 Phase III of its pilot program. Phase III
8 includes 14 locations with a potential of 426
9 customers. Phase III applications total 150 to
10 date which represents 35% of potential
11 customers. The Company, however, does not
12 include these expenses or revenue in this rate
13 filing.
14 Q. How much money is allocated to fund the
15 Company's Gas Infrastructure Enhancement
16 efforts?
17 A. In the last rate proceeding, 13-G-0136, the
18 Company was provided $750,000 annually from
19 Capacity Release and Off-system Sales Revenues,
20 for 4 years, starting in 2014, to fund its
21 program. This money was earmarked, but not
22 limited to assist in reducing CIAC payments,
23 supplying grants for low income and providing
24 rebates.

Q. Has the Company been utilizing the full amount of the funding since that case was settled?

A. No, it has not. As illustrated in Appendix L of the Gas Infrastructure Enhancement Annual Report filed in February under 13-G-0136, there is a lag in getting the programs up and running. In 2014, the Company did not spend any of the budgeted money. In 2015, spending on these programs began, although over $1.4 million of the $1.5 million had yet to be utilized. Projections for 2016 and 2017 show accelerated spending levels; however, a cumulative balance is forecast to exist at the end of the four year period.

Q. Does this Panel have any recommendations for how the Company should try to make up the difference between budgets and spending for its Gas Infrastructure Enhancement programs?

A. Yes. First, we recommend that the annual $750,000 funding from the Capacity Release and Off-System Sales Revenues continue for the term of the rate plan resulting from this case. Next, we also believe that the Company needs to be more aggressive when it comes to expanding

its reach through line extensions and possible new franchises to customers that do not heat with natural gas, but use fuel oil and propane.

Q. What should the Company do?

A. At a minimum, the Company needs to include a forecast of customers to be added from the Phase III pilot program as part of this rate filing. Based on the projected balance of funding allocated to the Gas Infrastructure Enhancement Program, the Company should be able to include Phase III without having to request additional funding.

Q. Does the Panel have any other recommendations to improve the results of the Company's efforts to its Gas Infrastructure Enhancement Program?

A. Yes. We believe that both the percentage of conversions for existing pilots, as well as the total level of new customers in the last couple of years has under-achieved what the Company could do if it focused more on this program. The lag in establishing a pilot for low income customer areas is especially disheartening. The Company has now revisited the rebates specifically designed for low income customers

and we hope that it can be tested in Phase 3, at the latest. We also recommend that the Company look at changing the eligibility criteria for its pilots so that more customers in more areas can be included. We would like to see them develop a standard that can be applied to the entire service territory, instead of a single main extension at a time. It is also not clear how extensive the Company's efforts are in pursuing customers that could be attached without CIACs or surcharges. The Company should provide a more specific plan for getting more existing non-heat customers and more non-customers on a distribution main converted. The Company should also be more aggressive on pursuing new franchises outside of its existing service territory. Available program funds may be utilized to help reduce new franchise costs if needed but such use should be addressed in the franchise certificate filing to ensure that the use is appropriate and does not hinder other program efforts. Future plans should also include a way to involve local municipalities to help determine the best areas of potential new

1 commercial and residential load, especially when
2 the municipality may be capable of providing
3 additional financial assistance even if it is
4 only in the form of public works support. The
5 Company should start identifying specific
6 municipalities by reviewing inquiries already
7 received through phone calls, emails or any
8 other form of communication customers have used
9 to identify a desire for natural gas service.
10 Q. Did you include any additional customer growth
11 for the increased pilot and related conversion
12 activity?
13 A. Yes. Staff included additional growth, above
14 the observed level of current trends, to
15 coincide with the Company's Gas Enhancement
16 pilot programs, as well as efforts to convert
17 other non-customers near or on existing
18 distribution mains. Staff's Gas Rates Panel
19 customer forecast includes an additional 2,150
20 customers in the residential marketing group and
21 an additional 350 customers in the commercial
22 marketing group. No additional changes were
23 made to the customer forecast.
24 <u>GAS ENHANCEMENT PERFORMANCE INITIATIVE</u>

Q. Do you propose an infrastructure enhancement performance incentive for the Company in this Case?

A. Yes. We propose an incentive of one basis point for each 10 percent additional increase in customers the Company is able to achieve, incremental to the Staff Gas Rates Panel's Rate Year (RY) customer growth targets. This incentive would be capped at five basis points annually. The Staff Gas Rates Panel forecasts customer growth of 2,500 firm customers in the RY. Our proposal would provide for a positive incentive of one basis point for each 250 firm customers that are added above this projection. This incentive should be capped at five basis points, which the Company would achieve if it adds 1,250 firm customers above the additional 2,500 firm customers included in the Staff Gas Rates Panel forecasts for the end of the RY.

Q. Do you propose a disincentive if the forecasted numbers are not attained?

A. No. Since the revenue requirement needed to establish a proper rate of return is contingent upon the number of customers and the projected

gas usage of these customers, any shortfall from the approved forecast will serve as its own disincentive.

DISTRIBUTED GENERATION (DG) AND NATURAL GAS VEHICLE (NGV) PROGRAM

Q. Describe the current Company DG and NGV programs.

A. The existing DG program was originally approved by the Commission on March 20, 2003, in Case 02-G-0858. It has been renewed by the Commission on March 20, 2006, and March 12, 2009, each time for three years. On November 18, 2011, the Commission again approved a three year extension of the DG Program, and at that time also approved the NGV Program. On May 15, 2015, in 14-G-0551, both programs were again renewed as pilot programs for an additional 3 year term. These programs provide shareholder loans to reduce the initial cost of customer investments in DG and/or NGV customer assets. As approved, the spending levels of the two programs are capped at $1 million per year, or $3 million over the three year extension term.

1 Under the DG program, as stated in the 2015
2 renewal order, six customers have participated
3 resulting in the installation of 12,125
4 kilowatts of gas-fired DG units at their
5 facilities, partially financed by $653,000 in
6 shareholder loans. Under the NGV program, as
7 stated in the January 2016 annual report to the
8 Commission, 7 customers are currently
9 participating resulting in increased natural gas
10 load of 293,589 thousand cubic feet of
11 incremental annual gas usage, partially financed
12 by $975,596 in shareholder loans.
13 Q. What recommendations does the Panel have
14 regarding these programs?
15 A. In its Order in Case 14-G-0551, the Commission
16 required the Company to request that these
17 programs become permanent, if the Company seeks
18 to extend them again in the future. In that
19 request, the Company was instructed to support
20 the reasons why these programs should be
21 incorporated into its tariff on a permanent
22 basis, eliminating the need to request further
23 extensions. We believe that the results of the
24 programs are worthwhile, and that the programs

should now be made part of the permanent tariffs as part of this proceeding instead of waiting for the end of the current pilot term.

Q. Does the Panel have any additional recommendations as to how the DG program could be improved?

A. The Company should continue the use of the DG program for Reforming the Energy Vision (REV) projects of electric companies in its gas distribution territories. In addition to participating in NYSERDA's New York Prize Program, other projects of National Grid, New York State Electric and Gas, Rochester Gas & Electric and municipal organizations should be actively pursued where natural gas improves the project.

Q. Does the Panel have any additional recommendations as to how the NGV program could be improved?

A. We recommend that a specific focus be established to direct this program towards replacement of fleet vehicles currently using diesel fuel to maximize the environmental benefits from using these funds. We also

1 recommend exploring an incentive for the Company
2 to convert diesel vehicles to natural gas.
3 Before an incentive can be developed, additional
4 market information is required. To that end,
5 the Company should be required to file a report
6 that demonstrates the potential number of fleet
7 vehicles that can be converted from diesel fuel
8 with the Secretary to the Commission within 90
9 days of the Commission's rate order in this
10 proceeding. At that time, a reasonable
11 conversion incentive may be included in the
12 Company's report and submitted for Commission
13 consideration.
14 PRIME WESTERN NY PROGRAM
15 Q. Describe the current Prime Western NY Program.
16 A. The Partnership to Revitalize the Industrial
17 Economy of Western NY (PRIME) was approved by
18 the Commission in the 14-G-0551 Order that
19 continued the NGV and DG programs, and became
20 effective on June 1, 2015. PRIME permits the
21 Company to give customer funding to buy down the
22 cost of purchasing/installing new natural gas
23 equipment, thereby lowering the customer's
24 payback. It has a term of 3 years with an

1 annual cap of $2 million/year, a total of $6
2 million. Customers must sign a performance
3 contract with a term of up to 7 years with
4 security. In addition to filing an annual
5 performance report, the program has some unique
6 features. It requires a $0.10/Mcf customer
7 charge as a contribution to overall distribution
8 system costs to benefit other ratepayers. In
9 addition, the Company is allowed to charge above
10 the otherwise applicable delivery rate if
11 necessary to recover the loan to the customer.
12 The Company has also developed a competitive
13 component to the program that allows third party
14 financial institutions or lenders to provide
15 loans to customers in the program. The loans
16 can be extended for a term from 6 to 7 years
17 giving increased flexibility to maximize project
18 economics.
19 Q. What activity has taken place to date?
20 A. The Company Energy Services Panel testifies on
21 page 50 that, to date, the Company has a
22 contractual agreement with one customer under
23 this program. Since, this is the newest program
24 the Company has undertaken it is too early to

make any additional recommendations at this time. However, it is our hope that this program, the DG program and the Area Development program can be utilized not only as intended but in conjunction with one another for the purpose of improving revenue, utilization of the distribution system and in support of REV projects as discussed within this testimony.

LOCAL PRODUCTION/RENEWABLE GAS SOURCE ISSUES

LOCAL PRODUCTION ISSUES

Q. Is the Company proposing any local production modifications?

A. Yes. The Company Gas Supply Administration Panel has proposed on page 31 of its testimony to implement a minimum delivery requirement of 1 MCF per day on any local production meter point and to eliminate the monthly receipt facility fee for all local production meters.

Q. Does Staff agree with the Company proposal?

A. Not entirely. Staff supports the removal of the monthly receipt facility fee for local producers, but does not agree with the minimum delivery requirement.

Q. Please explain why Staff disagrees with the

1 minimum delivery requirement proposal.
2 A. As described by the Company Gas Supply
3 Administration Panel, the Company currently has
4 973 local production meters with 191 of them
5 producing less than the Company proposed 1 MCF
6 per day delivery requirement. The Company
7 proposal would shut local production access of
8 these wells that are still providing local
9 indigenous gas to the distribution system and
10 transportation customers.
11 Q. Why is shutting down access of these wells to
12 the distribution system a problem?
13 A. This action creates the potential for currently
14 active production wells to shut down and
15 eventually be abandoned because of the inability
16 of the well owner(s) to remain financially
17 solvent. If abandoned, the well would need to
18 be properly closed in accordance with New York
19 State Department of Environmental Conservation
20 (DEC) requirements. If the owner is not
21 financially solvent and is incapable of closing
22 the well, responsibility to properly close the
23 well falls to an abandoned well fund maintained
24 by DEC. Our discussions with DEC staff indicate

that this fund does not have the capability of handling all the abandoned wells currently known to DEC. Adding additional wells to the DEC list needs to be avoided if at all possible. The reliability of the local production wells, especially low-flow intermittent wells connected directly to the Company's distribution system, was also at issue in a prior Company rate case, Case 00-G-1858 (Staff Witness Sano Testimony at 23). It continues to be an issue and this is not the first attempt by the Company to disconnect low flow wells from the distribution system. These wells are protected under the Public Service Law §66-g, in that the producer has the right to sell its gas to Distribution, or to transport its gas on the Company's system, and this right should not be denied.

Q. Are you recommending any adjustment to the Company's request for O&M expense funding for the Meter Shop?

A. On August 4, 2016, the Company filed an update to DPS-31, contained in Exhibit__(GPS-1). The follow-up response to DPS-31, Exhibit__(GPS-1), corrects the amount of Meter Maintenance fees

recognized in Company Exhibit__(RMF A-1) work paper page 3, from ($456,000) to ($447,920), because the Company mistakenly removed retest fees from its initial calculation. According to IR response DPS-126, contained in Exhibit__(GPS-1), the actual revenue associated with the meters that would have been removed cannot be precisely determined until removal. We do not believe any further funds should be required because we do not believe any of the meters should be removed. Any existing language in the interconnection agreement allowing for the removal of these meters should be removed.

Q. Does the Panel have any other recommendations regarding local production access to the distribution system?

A. Yes. The gathering systems connected to the distribution system must be in compliance with the New York Codes, Rules and Regulations 16 NYCRR §§ 255.9 and 255.625, where applicable, to ensure that these lines are properly odorized. We recommend that all lines connected to the distribution system be in compliance with the rules and regulations regarding odorization.

1 Q. How do you propose the Company accomplish this?
2 A. First, this requirement should be added to the
3 existing required Interconnection Agreement
4 between the local production entity and the
5 Company. Second, waiver of the current meter
6 maintenance charge for all interconnections
7 should be contingent upon the gathering system,
8 or individual line from the well meeting this
9 requirement.
10 Q. How would you enforce this requirement?
11 A. First, any Company-owned gathering systems must
12 be in compliance, regardless of any third party
13 production facilities that my share the Company
14 system. Second, the higher flow production
15 facilities as described in the Company's Gas
16 Supply Administration Panel's testimony on page
17 31 need to meet this requirement or the meter
18 maintenance charge is not waived. In addition,
19 the remaining low flow facilities must also meet
20 this same requirement for the waiver we suggest
21 in order for them to be in effect. Third, any
22 meter maintenance charges collected from non-
23 compliant facilities should be set aside in a
24 deferred account for the sole purpose of funding

odorization of production facilities that are not in compliance.

Q. What role do you see the Company serving in this effort?

A. Through the interconnection agreement and the collection of meter maintenance fees, the Company has an opportunity to affect safe operation of these gathering systems and lines. The Company should file a survey of the gathering lines for all 971 meter connections identified previously with the Secretary to the Commission within 60 days of the order in this case. This survey should include the responsible entity for each meter, the status of the annual production through each meter, and the status of compliance with the rules and regulations regarding odorization of gas. The Company should also recommend a possible incentive for itself to implement this effort for odorized gas at the same time it ensures that the production facilities can remain on the distribution system, eliminating the possible threat of shutting in wells.

INDIGENOUS AND RENEWABLE GAS SUPPLIES (RNG)

Q. What are indigenous and renewable natural gas (RNG) sources?

A. As stated in the U.S. Energy Information Administration's Glossary, renewable energy resources are those that are naturally replenishing but flow-limited. They are virtually inexhaustible in duration but limited in the amount of energy that is available per unit of time. Renewable energy resources include biomass, hydro, geothermal, solar, wind, ocean thermal, wave action, and tidal action. RNG supplies are those produced from renewable biomass, such as the gas product from landfills and anaerobic digesters.

Q. Why does the use of RNG supplies need special focus at this time?

A. The U.S. Environmental Protection Agency (EPA) is taking steps to further reduce emissions of methane rich gas from municipal solid waste (MSW) landfills. Under rules issued on July 15, 2016 (Rule and Implementation Information for Standards of Performance for Municipal Solid Waste Landfills; https://www.epa.gov/ttn/atw/landfill/landflpg.ht

ml), new, modified and existing landfills will begin capturing and controlling landfill gas emissions at levels that are one third lower than current requirements, updating 20 year old standards for existing landfills. Combined, the final rules are expected to reduce methane emissions by an estimated 334,000 tons a year beginning in 2025 – equivalent to reducing 8.2 million metric tons of carbon dioxide. EPA estimates the climate benefits of the combined rules at $512 million in 2025 or more than $8 for every dollar spent to comply.

Q. What has the Company done regarding renewable gas sources?

A. In its response to IR DPS-196, contained in Exhibit__(GPS-1), the Company indicates that it does not currently offer any programs to assist customers in pursuing geothermal or solar technologies. But it is the Company's experience that if natural gas is available, a natural gas heating system is almost always more cost effective (on a life cycle basis) than a geothermal or solar thermal system due to the very high initial costs of these systems, which

1 can't be overcome by their low operating costs.
2 This conclusion is backed up by a recent NYSERDA
3 Study (Report Number 14-39) entitled Heat Pumps
4 Potential for Energy Savings in New York State,
5 issued March 2015.
6 Q. Why is it useful to develop RNG sources in the
7 Company's service territories?
8 A. Indigenous and especially RNG supplies that
9 reside in territory can help to replace the need
10 for additional upstream pipeline capacity.
11 However, these renewable resources must be
12 equivalent in quality to pipeline gas.
13 Q. Does the Company currently have standards and
14 are they readily available to developers and
15 producers?
16 A. Yes. As identified in the Appendix of Standard
17 Form Agreements in the Company's Gas
18 Transportation and Procedures Manual (GTOP), a
19 Pipeline/Gatherer Interconnection Agreement
20 exists for the purpose of receiving gas from
21 natural gas producers and gatherers into the
22 Company's distribution system.
23 Q. Do you have any recommendations?
24 A. The existing Interconnection Agreement included

in the GTOP was designed for receipt of indigenous gas from non-renewable sources. This standard agreement should be reviewed and may need to be modified, if necessary, to accommodate and to encourage RNG sources. At a minimum, it must include a clear delineation of equipment ownership and responsibility for operation and maintenance between parties. If the current delineation of production well and metering equipment does not work in a RNG situation, the proper modifications to the agreement should be made. A separate purchase agreement is acceptable, if the Company is buying the gas, but the gas should also be available for transport to third parties. The Company should be required to report any changes needed to the agreement that can be incorporated into the GTOP after a comment period, and a program to add interconnects with RNG sources in its territory, to the Secretary of the Commission within 90 days of the Commission's order setting rates in this proceeding.

WORKFORCE DEVELOPMENT

Q. What is a workforce development program?

A. A workforce development program is a training program to match potential workers' skills with that of a given industry, in this case the construction, operations, and maintenance of the Company's natural gas distribution system.

Q. Why is a workforce development program necessary?

A. A workforce development program is necessary for a number of reasons. The first is the general aging of the workforce in the utility industry. According to the Center for Energy Workforce Development (CEWD) in its 2015 Workforce Survey, approximately 36% of the energy industry workforce in the United States will need to be replaced in the next 10 years. The CEWD also states that 10% of the energy workforce is currently ready to retire. This information is publicly available on the CEWD's website, http://www.cewd.org/surveyreport/CEWD2015SurveySummary.pdf. With the impending loss of such a large part of the energy workforce, there should be a plan to train and develop the next generation of utility workers. Second, all natural gas utilities in New York State have

been required to increase the rate of replacement of leak prone main, as well as increase other infrastructure enhancement efforts. In order to accomplish this heightened workload, there must be a larger pool of workers for physical plant construction.

Third, we believe that utilities in New York should be performing more frequent inspections of their construction activities using inspectors trained on construction practices and Company procedures. A workforce development program can provide trained and qualified gas inspectors.

Q. What are the other benefits of a workforce development program?

A. One benefit is that a greater pool of workers trained and qualified to work on natural gas in the local area could reduce the cost of contract bids for all infrastructure enhancement work. Ultimately, this cost savings could be passed on to ratepayers. A second, societal benefit is that it will lead to potential job creation.

Q. How has the Commission addressed the need for workforce development?

A. The Commission has given a clear signal that it intends to ramp up modernization of the existing infrastructure, through the generic Leak Prone Pipe (LPP) case and through the incentives for acceleration of LPP removal in rate cases like Central Hudson, Case 14-G-0319, and O&R, Case 14-G-0494.

Q. Does the Company already have a long term workforce development plan?

A. Yes. As described in the response to DPS-165, contained in Exhibit__(GPS-1), the Company has implemented an approach to both workforce development and resource replacement. These efforts include relationships with local colleges and universities, staffing resource planning, and its Operator Qualification Program for hourly employees. Contractors also receive training through the Company's Operator Training department. The Company also utilizes extensive outreach efforts to attract employees.

Q. Does the Company link Contractor performance to contract compensation?

A. As described in the response to DPS-167, the Company does not offer specific itemized

1 performance incentives or penalties based on
2 contractor's work or schedule performance. The
3 Company does employ Blanket Pipeline Program
4 contracts for Pipeline, directional drilling,
5 restoration services and miscellaneous and
6 emergency pipeline construction.
7 Q. Does the Panel agree with the Company's
8 approach?
9 A. Generally yes, though we do recommend certain
10 changes. Staff has reviewed workforce
11 development activities in the most recent
12 Central Hudson, Orange and Rockland, New York
13 State Electric and Gas, Rochester Gas &
14 Electric, Con Edison, National Grid NY and
15 National Grid LI rate cases. Two primary tasks
16 that a distribution Company can perform to
17 facilitate workforce development are outreach
18 and education activities as well as providing
19 training and structure for steady employment for
20 both contractors and Company workers. With one
21 exception, the Company's interrogatory response
22 identifies that many aspects of a comprehensive
23 program exist. The one area of improvement we
24 recommend is to establish a structure for

contractors to maintain long-term employment, thus receiving maximum benefit for Company and contractor investment in workforce development. This structure can successfully support long-term employment by including multi-year contracts with performance clauses, prices established through a bid process, and training similar to the training offered to the Company's own employees. In addition, annual extensions for the highest performing contractors can be an additional benefit for the entire workforce, the Company and customers alike. The Company should review its contractual agreements and identify areas of improvement and file a report to the Secretary to the Commission no later than 60 days after an order in this proceeding.

RESEARCH & DEVELOPMENT

Q. Describe the Company's involvement in Gas Research and Development (R&D).

A. The Company participates in R&D through both traditional internal program, funded through base rates, and a Millennium program, funded through surcharge on the Delivery Adjustment Charge (DAC) statement. The traditional program

consists of what the Company describes as an internal component, which addresses technologies nearing commercialization, conducting technology demonstrations, assessments and transfers. In addition, the traditional program also contains an additional component, where the programs are managed by NYSEARCH and NYSERDA. The Millennium program is set up through NYSEARCH to support projects developed and performed by other outside organizations that specialize in natural gas R&D.

Q. Is there a concern over what the Company identifies it includes in its R&D program?

A. Although an internal component is included in the description of the traditional program, at p. 33 the Company's Energy Services Panel states that the Company does not internally conduct R&D. While we do not have an issue with what the Company is including in its program, it should be noted that this traditional program could support Company projects and external projects alike that are not allowed to be conducted through the Millennium program, such as end user technology improvements as well as

1 projects that cannot meet the Millennium funding
2 mechanism.
3 Q. Does the Panel agree that NYSERDA funding should
4 be included in the R&D budget?
5 A. No. The Company states that it includes a
6 NYSERDA portion in its external component of the
7 traditional program; however, we believe that
8 this is not being identified and accounted for
9 correctly. The R&D budget should be limited to
10 expenses that are associated with natural gas
11 projects and it is the panel's understanding
12 that NYSERDA does not perform any natural gas
13 R&D. The Energy Services Panel states that
14 these costs are part of a mandatory assessment
15 (Energy Services Panel at p. 36). We believe
16 that they should be removed from the R&D budget
17 and included elsewhere in the Company's ledger,
18 as described in the Staff Accounting Panel
19 testimony.
20 Q. What adjustment should be made?
21 A. Any adjustment will be included in the Staff
22 Accounting Panel testimony.
23 Q. Does the Panel have a recommendation regarding
24 the level of surcharge collections that the

1 Company receives through its DAC?
2 A. Not at this time. As identified in filed DAC
3 statements, the Company has been decreasing the
4 level of surcharge it is collecting from its
5 customers over the past several years. While a
6 maximum level of $0.0174/Dth was established in
7 the January 31, 2000 Order on R&D from case 99-
8 G-1369, the Company is currently below that
9 level. For example, in 2016, the Millennium
10 Fund R&D surcharge was being collected at a rate
11 of $0.0065/ccf. Since the Company does not
12 project any changes in its $900,000 R&D
13 Millennium Fund budget for the RY, the
14 surcharge, through the DAC, would remain at a
15 similar level to match its collections with the
16 budgeted expense. But we would prefer that the
17 Company identify additional gas safety projects
18 designed to improve the overall safety of its
19 distribution systems, and adjust the surcharge
20 accordingly.
21 Q. Can you summarize what types of R&D the Company
22 includes in its annual budget?
23 A. The Company files a triennial report with the
24 Commission which details the programs the

1 Company is involved in. The most recent of
2 these reports was filed in March 2016, in Case
3 98-G-1304 and is referred to by the Energy
4 Services Panel. In the report the Company
5 identifies programs that consider large
6 industrial energy assessments, micro grid
7 thermal loads, natural gas vehicles and stations
8 as well as welded seams on gas pipes.
9 Q. Are there particular programs that the Company
10 should include in its R&D, which they are
11 currently not funding?
12 A. A Residential Methane Detector program is very
13 important. Consistent with what the Commission
14 has ordered in recent rate filings like Orange
15 and Rockland, 14-G-0494, gas utilities are now
16 being asked to reallocate over-collection
17 balances that were accumulated for the support
18 of safety programs, like providing rebates on
19 residential methane detectors for utility
20 customers to help to identify potential gas
21 leaks. However, the Company does not have an
22 over-collection. Instead, there is money
23 available from non-compliance with pipeline
24 safety regulations measures that can be used

towards residential methane detectors and this possibility will be discussed in more detail as part of the Staff Gas Safety Panel testimony.

REV DEMONSTRATION PROJECT PARTICIPATION

Q. Does the Company have any projects underway related to the REV proceeding?

A. Currently, the Company is collaborating with National Grid to provide gas service for the Buffalo-Niagara Medical Campus demonstration project. The National Grid project is creating a micro-grid installation which includes a natural gas fueled distributed generation facility. The Company is also collaborating with two municipalities for their micro-grid project proposals. In addition to the potential micro-grid projects, the Company currently has three programs, including the Network Enhancement Program; Distributed Generation Program; and the Natural Gas Vehicle Program. These programs indirectly contribute to and/or support certain REV goals, such as reduced environmental emissions through appliance or transportation equipment conversions, and financing incentives for installing natural gas

fired distributed generation.

Q. Does the Company have any other direct projects which conform to the directives of the REV proceeding?

A. Not at this time.

Q. What do you recommend?

A. We recommend that the Company continue to collaborate with other electric distribution utilities on their electric REV projects but it should also create alternate heating solutions and services for customers that may combine gas service with renewable energy sources, such as geothermal and solar resources.

Q. What are new customer heating solutions and services?

A. The May 19, 2016 REV proceeding Order discusses developing the regulatory environment in which a utility will naturally and aggressively pursue system solutions that simultaneously create consumer benefit and increase the utility's earning opportunity. This Company is solely a gas distribution utility and has no ability to provide direct improvements or modernization to the electric distribution grid as a distributed

system platform services, but is able to provide natural gas as a fuel source for various generation needs for new market participants and provide gains toward environmental goals through expanding the use of natural gas. In addition to continuing to collaborate with electric distribution utilities, municipalities and market participants on their electric REV projects, it should also create an alternate non-pipe services solution such as using Compressed Natural Gas (CNG) or Liquefied Natural Gas (LNG) technology to provide its natural gas service. This would enable the Company to further expand its customer base to stranded portions of its service territory and beyond where distribution main extensions may not be feasible. This could also enable the Company to create a new revenue stream for CNG supply services and further support the financial viability of non-pipe expansion projects. The Company could also collaborate with third party providers of CNG or LNG producers to provide the production and supply services while maximizing the use of its

distribution facilities to provide the source gas for the non-pipe solution. A potential non-pipe service would also allow the Company to contribute toward environmental goals by displacing the use of higher emission fuels such as fuel oil and propane.

ELECTRIC GENERATION ISSUES

Q. Please describe the pertinent issue governing electric power generators' use of the Company's systems.

A. Power generation customers have different economic and operating characteristics than other non-firm customers. For example, power generators are subject to intraday and daily swings, as dictated by the NYISO dispatch needs. Because of this, the Company already requires generation customers to comply with strict balancing provisions that require a +/- 2% market based cash out imbalance tolerance. These swings and possible resulting unauthorized use of gas may impose serous reliability issues on the distribution system.

Q. What issues or improvements does this Panel propose regarding a generator's unauthorized use

of gas?

A. First, we recommend that the Commission require a change in the balancing rules for the power generators. As identified in Distribution's tariff leaf 291, a daily deficiency imbalance from 10% to 15% of usage is cashed-out at 110% of the Index Price of gas. This price schedule should be modified so that any daily deficiency imbalance from 2% to 15% is cashed out at 110% of the Index Price of gas. This change will make the Daily Deficiency Imbalance tiers consistent and symmetrical with the Daily Surplus Imbalance tiers. Second, the generators are paying a charge for balancing services that equates to 2% of their usage. The imbalance tiers listed on tariff leaves 290 and 291 should be properly labeled as penalty tiers since these tiers apply to the excess beyond the 2% level of the service provided. Daily balancing tier levels applied to power generators or any daily balanced customers should be clearly identified as to what is a penalty and what is a gas cost. With daily balancing, the Daily Gas Index Price is the actual gas cost. Surcharges to the price

applied for sale of gas to a customer by a Company due to an under-delivery and discounts applied to the price credited to a customer for sale of gas to a Company due to an over-delivery should clearly be identified as penalties in the tariffs and GTOP manual.

Third, tariff leaf 293 (Special Provisions Item 7) states that if a power generation customer takes gas service during a period of interruption, the customer will pay to the Company an additional $7 per Mcf charge for such gas. We are concerned that this charge is not a sufficient deterrent to prevent the unauthorized use of gas. The actual price of gas to be charged needs to be identified in this special provision. We recommend that the additional charge be raised to $25 per Mcf during non- Operational Flow Order (OFO) periods and $50 per Mcf during an OFO.

Q. Are there other recommendations?

A. Yes. Current tariffs also need to require that new generators, and existing ones that fail to comply with an interruption, should install and pay for remotely operated valves. Failure to

comply with utility initiated interruptions can be just as serious as OFO non-compliance. These requirements will provide incentive to electric generators to better manage imbalances and to respect interruption notices which helps preserve system reliability for firm customers.

TRANSPORTATION & BALANCING

Q. What improvements does this Panel propose regarding retail access procedures and charges?

A. The charges and terminology associated with city-gate balancing need to be updated.

Q. What is city-gate balancing?

A. City-gate balancing is the daily verification of actual deliveries by transportation customers or their energy service company (ESCO) to the Company's respective city-gates, and the amount of gas that a monthly balanced customer was instructed to deliver or a daily balanced customer actually consumed.

Q. What is the Panel's concern regarding the tariffs regulating these deliveries?

A. We are concerned with the value of the charges for deliveries that fall below the daily delivery quantity the Company instructed the

transporters to deliver. According to the GTOP manual on page D-6, transporters are required to deliver a minimum 95% of the daily forecast provided by the Company without incurring charges or penalties. Failure to do so, especially for larger volume customers, can place an unnecessary burden on the distribution system and utilization of upstream assets. Deliveries falling below this level subject the transporter to purchase gas from the Company under the SC 11 Deficiency Imbalance Sales Service. During authorized periods a deficiency imbalance sale is at 110% of the per hundred cubic foot (Ccf) Total Gas Cost for the month (equivalent to the Company's weighted average cost of gas) from April through October and 125% of the per hundred cubic foot (Ccf) Total Gas Cost for the month (equivalent to the Company's weighted average cost of gas) from November through March, market based commodity rate plus a penalty charge of $10 per mcf for non-operational flow order (OFO) and $25 per mcf during OFO events.

Q. What does the Panel recommend?

A. To provide a sufficient incentive for the protection of system integrity, we recommend the penalty for under delivery during non-OFO events be increased from $10 to $25 per mcf and for OFO events be increased from $25 to $50 per mcf. This change should be applicable to all monthly balanced customers, firm and non-firm alike. We also recommend that these charges be properly identified in tariffs as "penalty" charges. In addition, daily balancing tier levels applied to daily balanced customers should also be clearly identified as to what is a penalty and what is a gas cost. With daily balancing, the Daily Gas Purchase Price is the actual gas cost. Surcharges to the price applied for sale of gas to a customer by a Company due to an under-delivery and discounts applied to the price credited to a customer for sale of gas to a Company due to an over-delivery should clearly be identified as penalties in the tariffs and GTOP manual.

Q. Does this conclude the Panel's testimony at this time?

A. Yes.

BY MS. AISSI: (Cont'g.)

Q. Panel members, did you prepare or identify any exhibits to accompany your testimony?

A. Yes, we did.

Q. And is that document identified as Exhibit GPS One?

A. Yes, it is.

Q. Do you wish to make any corrections to that exhibit?

A. No, we do not.

MS. AISSI: Your Honor, I ask that the exhibit be marked for identification.

A.L.J. LECAKES: GPS One will receive Exhibit 266 for identification.

MS. AISSI: Thank you.

The Panel is now available for questions.

A.L.J. LECAKES: Mr. Mager -- am I correct that the company has no cross for this panel?

MR. DEL VECCHIO: That’s correct, your Honor.

A.L.J. LECAKES: Thank you.

Mr. Mager, whenever you’re ready.

CROSS EXAMINATION

BY MR. MAGER:

Q. Panel, I -- I just have two topics I want to cover. The first deals with customer-conversion efforts. I believe you start testifying to that on page 10.

And then on -- on the bottom of 7, going into 18, you start describing a Gas Enhancement Performance Initiative. Are -- are those two topics related? Are they both dealing with increasing the number of customers?

A. (Sano) Yes, they are.

Q. Okay. Now currently, there's money already in base rates to fund NFG's efforts to add new gas customers, correct?

A. There are capital money -- monies involved, yes.

Q. So -- and also I -- I look at -- on page 13 you mention that there is a -- a 750 thousand dollar a year rate allowance to fund that program. Is that --?

A. That is not in base rates.

Q. Okay. Where -- where is that money coming from?

A. That 750 thousand dollars is -- comes

from the capacity release and the call-system sales revenue that usually flows back to current customers.

Q. Okay. So this is money that otherwise would have been returned to customers, but is being held to pay these efforts to expand the customer number?

A. Right. This was set up in the -- as part of the settlement that the Commission approved in the -- let's see. I think it's 14-G-0136.

Q. Okay.

UNIDENTIFIED SPEAKER: Thirteen.

BY MR. MAGER: (Cont'g.)

Q. And --.

A. 13. Sorry. 13-G-0136.

The years are blending together. I -- I'm sorry.

Q. That's okay. For me, too.

Now, the -- now the company has not so far been spending this money at nearly the rate anticipated, correct?

A. At this point, it's Staff's understanding that of the -- in the two years of this program there's been 1.5 million dollars collected and just barely over a 100 thousand dollars have been spent.

Q. And you testify that -- on page four,

that the company needs to be more aggressive?

A. Yes, we do.

Q. And on page 15, you -- you indicate that it is underachieved.

A. Well, I think parts -- parts of it have underachieved and other parts maybe do -- may be just getting started.

What we did notice is that -- and this is, I think a question more for the actual growth experience since these programs are being placed, which is handled by our Gas Rates Panel, all right, because they identified that there's about -- I think if you look at the numbers, it would be about a half a percent of growth since these programs were put in place, but what we wanted to state was that the data that was used to do that analysis -- and again, I think the Gas Rates Panel will be able to answer these questions more specifically, show that none of the line-extension pilots, the phase one, phase two, phase three type stuff that was talked about with the Energy Services Panel this morning, were included in any of those numbers because most of the 79 people who actually converted, occurred after the data was received and the analysis was done.

So, in other parts of that program,

applying the rebates, applying the marketing effort, the survey groups, that go after skips and other things like that, is what helps get the growth up.

Q. Okay. Now, we talked about a hundred -- I'm sorry 1.5 million being earmarked and they've spent 100 thousand on the -- the one -- approximate 1.4 million that's not -- that hasn't been spent.

Is -- is -- are companies -- are customers getting interest on that -- the company paying interest on that?

A. I'd have to go back to the Rates Panel and ask. I -- it -- they -- they may not be.

Q. Okay. Now, even though --.

A. Especially if it's going to be spent. If it's -- I'm not going to give the company interest on the money while it's sitting there.

Q. Okay. Now even though the -- the -- the Staff is -- even though the money has not been spent to date, Staff wants to create an incentive to pay the company more money to increase the number of customers? Is that -- is that what you're recommending?

A. Yeah. Our intent is to increase the number of customers that the company serves and we've already seen the benefit of the programs that were in --

in -- put in place two years ago and we want to see them actually get more aggressive and add more because we want to see the use of propane and fuel oil decrease and -- and -- and more natural gas utilized.

Q. And this program is targeted at residential customers, correct?

A. Residential and commercial.

Q. Okay. Let's -- let's jump ahead to page 46 of your testimony, please.

There's a section on page 46 entitled Electric Generation Issues. Do you see that?

A. Yes, we have it.

Q. Okay. On page 46, starting at line 11, you discuss how electric generation customers have different -- different economic and operating characteristics from other gas customers. Do you see that?

A. Yes, we do.

Q. Okay. And NFG has strict balancing provisions on electric generation customers --

A. Yes.

Q. -- correct?

A. Yes, they do.

Q. And you indicate that swings can

impose serious reliability issues on the distribution system. Is that --?

A. Yes, we do.

Q. Okay. How many times has that happened in the NFG's service territory in recent years?

A. Counsel, I don't think we have any data like that, that would show that there was a specific problem with -- with -- within the NFG territory itself.

Q. Okay. So then the thing --?

A. This is more of a general policy situation that we have been putting in place, which started back with the -- the Central Hudson Rate case, G-0139. I think that's -- that's a 14.

Q. But -- so your -- your concern is that electric generators may be using gas when they shouldn't?

A. What actually happened was there was a -- a -- a ruling that came out -- or -- or -- or a guidance or policy statement that came out from the New York ISO that indicated that unless something was specifically identified as unauthorized gas, that the generators could actually utilize it as part of -- of their bid procedure to -- to set electric rates and unfortunately we totally completely disagreed with that position and that's why since the Central Hudson case, we

have been clearly trying to identify anything beyond balancing service that the customer pays for on a daily balancing situation.

Excuse me. I got to stand up.

Q. No, whatever you -- you need.

A. Yeah.

On a -- on a daily balancing situation if they're not paying for it, then essentially it's unauthorized use of gas and so we have both in that case, Rochester Gas Electric, NYSEG case, Orange and Rockland and recently in both the ConEd and the Keyspan New York -- Grid New York with the Long Island cases. We've taken similar positions where we're saying anything beyond the balance of service being paid for is essentially unauthorized use of gas and needs to be identified as a penalty.

It's not that we don't allow them to do it. It's just that we have to make sure that they realize that this is penalty-gas prices they're paying just because there is a surcharge or a -- well, usually there's a surcharge if they're using firm customer's gas and they're not -- they're not paying for it, so they basically put a surcharge on top of it. We want to make sure that the ISO understands that that is a penalty

piece, not the actual base -- base cost of gas.

Q. Okay. And I -- and -- and you also recommended increasing the charges for that gas.

A. No. I think that we charge -- we discussed --

Q. On page 48.

A. -- was using -- yeah. If there's unauthorized gas of other gas -- if the non-firm customer uses gas when they're told to get off the system and not use gas, we increase those penalties. We increase that from -- and I believe it was from ten dollars to 25 dollars, or if there's an OFO, it goes from 25 dollars to 50 dollars that they'd pay.

Q. Right. And now -- and so I --I -- you've made clear the concern with respect to power generators, but am I correct starting on page 49, you're making -- you're recommending similar -- similar changes to non-generation transportation customers?

A. We're not aware of any problem with just changing the nomenclature on the daily balancing tiers for non-power generation customers who aren't bidding into the -- the New York ISO.

However, the other increases for the unauthorized use of gas, we felt were also appropriate for

all customers because the situation that develops is that the existing tariffs are -- are set up as a percentage of current gas prices and since those tariffs were set up, the gas prices have collapsed to such a degree that any percentage that you use, has not been -- it cannot be really beneficial as a deterrent to force people -- our customers to actually stay within the boundaries of what they're paying for. So those increases we felt were necessary to replace the incentives that used to be -- this incentive that used to be there when gas prices were higher.

Q. Well, let -- let's just take a step back.

You -- you're not aware of actions by non-generating transportation customers that have jeopardized reliability on NFG's system, right?

A. I'd have to go -- no, I -- I -- I don't -- I haven't asked the company for any information that would back up how out of balance the daily balance of customers have been --

Q. All right. So --

A. -- or even the monthly balance customers.

Q. -- so sitting here today, the -- the

concern about reliability and impacts on the system, you have no evidence that non-generating transportation customers are causing any specific problems?

A. This proposal is primarily a general policy move that we --

Q. All right.

A. -- are making statewide.

Q. Okay. Now on page 50 you discuss the economic impacts of failing to deliver adequate gas and you -- you state that there's a deficiency imbalance sale at a 110% of the company's weight average cost of gas. Do you see that, kind of in the middle of the page?

A. I don't see it, but I do remember it. I do know you're right.

A.L.J. LECAKES: It's lines --

A. (Cont'g.) Oh, I got it.

A.L.J. LECAKES: -- 12 --

A. (Cont'g.) We got it.

A.L.J. LECAKES: -- 13.

A. (Cont'g.) We got it.

A.L.J. LECAKES: Yeah.

A. (Cont'g.) All right.

BY MR. MAGER: (Cont'g.)

Q. Okay. And then that's -- that's

during kind of the warmer months, April through October and that -- now if there's -- it goes up to a 25% hit for the winter months, correct?

A. Correct.

Q. So, that's -- and the purpose of either imposing a 110% of -- of the company's average cost or a 125% of the average cost is to create a disincentive to -- to customers for being out of balance, right?

A. Yes.

As an example in the past, if you had gas that was priced at a -- at ten dollars, which it was back in the -- in the -- in 2005 to 2009, you -- ten percent would have been a dollar. All right. Now, it's down to 20 cents. If it's two dollars, then ten percent would be an -- a -- a 20% error.

We don't think that the 20 cents handles it and we felt that it needed to be higher than it was before also.

Q. Well, isn't there -- isn't there also ten dollar and 25 dollar penalties for non-OFO and -- and during OFO events that -- that --

A. Well, we --

Q. -- are currently in effect?

A. -- I think we've seen the ten dollars

and the 25 dollars as replacements for the ten percent and the 25 percent. If that's not clear, then I -- I apologize, but I think we see that more as a replacement.

Q. So --.

A. We're not -- we're not trying to double up on it.

Q. Right.

But you're -- the gas now is -- is it fair to say two dollars a dekatherm, maybe less?

A. It -- yeah, maybe two fifty at the highest right now --

Q. Right.

A. -- especially --

Q. So being --

A. -- in this area.

Q. -- so being charged ten dollars per dekatherm is a pretty significant penalty, is it not?

A. Well, pure and simple, if you stay within the -- the tariff requirements of what you're doing, you don't have to worry about it because you're not paying it.

Q. Right.

But if -- but it's -- it's intended to be a strong disincentive.

A. Right and we think it is.

Q. But you're -- in this case you're proposing to -- to more than double it to go from ten dollars to 25 dollars, even though there's no -- even though the ten dollar per dekatherm penalty is five -- more than five times the cost of gas as it is, you're proposing to go from ten dollars to 25 dollars, making it essentially more than 12 times the cost of gas.

A. Okay. We are -- we are definitely putting a big increase on it and we're doing it on purpose and the purpose is two-fold.

Number one, we're trying to be consistent statewide with all the companies. There are a few companies that actually are beyond that and we didn't actually recommend changing them, in any of the -- their rate cases. As an example, Grid -- National Grid New York and Long Island's tariffs call for -- for the OFO situation to be 100 dollars and that's been in place for quite some time now. We didn't -- didn't go to that, but since they were already beyond what our recommendation was, we -- we didn't take any issue with that.

However, here we're trying to be consistent with the other upstate companies. NYSEG, RG&E, Niagara Mohawk's territory and Central Hudson. We're

trying to be as consistent as we possibly can.

In addition, one of the things we're doing is that if we do allow customers to continuously use that -- and again, I say -- like I said, we don't have any -- any real information saying that that's been going on in NFG, but to protect the reliability, we're trying to make sure that the incentive -- the -- the disincentive exists, so that we don't develop a need for additional pipeline or storage capacity, which is becoming increasingly difficult to obtain.

Q. Well, let -- let me ask you this.

When we -- when we talked about the ten percent penalty that went to 110% of WACOG or a -- or a 125% WACOG, you testified that the impact of that disincentive is less now because gas prices have declined?

A. Yes.

Q. Right?

A. Yes.

Q. So when -- when a ten dollar or -- let's say -- let's use the 25%, maybe it's easier.

So the 25% penalty on ten dollar gas is two dollars and 50 cents. On -- on -- on two dollar gas it's only 50 cents. So it's a -- so, that's -- your position is that it -- because gas prices have come down,

the -- the incentive -- the percentage incentive has gotten weaker?

A. It's become meaningless, to tell you the truth.

Q. Okay. But now let's -- let's flip it and look at the -- the other penalties that were ten dollars in MCF and 25 dollars in MCF now, that you want to move from 25 to 50.

Isn't it also true that as gas costs have declined, the ten dollar and 25 dollar penalties have become even stronger disincentives because now, instead of being subject to ten dollar or 25 dollar penalty on ten dollar gas, you're basically -- the way the numbers are now with gas only two dollars a dekatherm or less, those -- those penalties are already significantly harsher than they were before gas prices declined?

A. Well, that's one way to look at it. I'm not sure that's the only way to look at it.

Q. No. But we --.

A. At the same time -- at the same time with the fact that the gas prices have dropped as much as they have, you would think that -- you said the ten dollars and 25 dollars, as they exist, could be more readily absorbed in somebody's operating cost and they

wouldn't be -- and they wouldn't have a problem doing it because their gas prices have dropped. It's one of the reasons why we're -- we think it needs to be increased because it's become less meaningful and not more meaningful statewide.

Q. It's very -- it's actually become a bigger penalty on a percentage basis, than it ever was.

A. Well, like I said, that's one way to look at it.

Q. Okay.

A. On a percentage basis, you're right. I'm not sure percentage basis is the right way to look at it.

Q. Okay. And so -- and so just so I'm clear, this proposal to change the -- the penalty figures is not based on any activity that you're aware of among transportation customers, or their marketers in the NFG service territory?

A. No. We would -- you have -- you have different situations that I'm not -- I'm not aware of any obvious large problem. I think that if we check with the company and ask them directly for their imbalances, which have not been a problem, we will see that there might be an occasional problem, with a customer to --.

Q. Well, isn't -- isn't it true that in this case actually, the company proposed to increase the penalties, or charges only on electric generators and it was Staff in this case, who is proposing to expand those increases from electric generators to all transportation customers?

A. Well, we feel that that -- that only doing it to the electric generation customers may have been discriminatory.

MR. MAGER: Okay. I -- I have nothing further, your Honor.

MR. AISSI: Thank you.

A.L.J. LECAKES: Mr. Sano, what -- why didn't Staff ask for that information about non-generating customers from the company?

MR. SANO: Basically because we were going to do -- we were going to follow our general policy statewide regardless of what they told us.

A.L.J. LECAKES: Okay. Staff, would you like to confer with the Panel about redirect?

MR. FAVREAU: Sure.

A.L.J. LECAKES: Let's go off the record until they're done.

(Off-the-record discussion)

MR. FAVREAU: There's no redirect, Your Honor.

A.L.J. LECAKES: Thank you.

Panel is excused.

Let's go off the record.

(Off-the-record discussion)

A.L.J. LECAKES: Company, please call your next witness, or panel.

MR. NICKSON: The Company calls the Gas Supply Administration Panel.

A.L.J. LECAKES: Panel members, could you please identify yourself by name and business address?

MR. CEJ: I'm Christopher A. Cej, 6363 Main Street, Williamsville.

MR. MICHALSKI: Robert M. Michalski, 6363 Main Street, Williamsville.

MR. MCAVOY: Kenneth McAvoy, same address.

A.L.J. LECAKES: Panel members, please rise and raise your right hand.

Do you swear or affirm that the testimony you're about to give today is the whole truth?

MR. CEJ: I do.

CHRISTOPHER A. CEJ; Sworn

MR. MICHALSKI: Yes.

ROBERT M. MICHALSKI; Sworn

A.L.J. LECAKES: And --

MR. MCAVOY: I do.

KENNETH MCAVOY; Sworn

A.L.J. LECAKES: -- please be seated.

Mr. Nickson, are you going to get their testimony into the record?

MR. NICKSON: I will, yes.

A.L.J. LECAKES: Thank you.

Proceed.

DIRECT EXAMINATION

BY MR. NICKSON:

Q. Panel, you have in front of you a document entitled The Direct Testimony of the Gas Supply Administration Panel consisting of 62 pages of questions and answers?

A. (Cej) Yes.

Q. And was that document prepared by you or under your supervision?

A. Yes.

Q. Do you have any changes or corrections

to the testimony?

A. No.

Q. And if I were to ask you the same questions today, would your answers be the same?

A. Yes.

MR. NICKSON: Your Honor, I would ask that the direct testimony of the Gas Supply Administration Panel be incorporated into the record as if given orally today.

A.L.J. LECAKES: Granted and that testimony appears on the disk from the company, testimony under the folder Direct Testimony.

Insert testimony of the Gas Supply Administration Panel

1 **Educational and Professional Background of Panel of Witnesses**

2 Q. Please state the members of this Gas Supply Administration Panel.

3 A. We are Christopher A. Cej, Kenneth B. McAvoy and Robert M.

4 Michalski.

5 Q. Mr. Cej, please state your business address.

6 A. My business address is 6363 Main Street, Williamsville, New York,

7 14221.

8 Q. By whom are you employed and in what capacity?

9 A. I am employed by National Fuel Gas Distribution Corporation

10 ("Distribution" or "Company") as Assistant General Manager within

11 the Gas Supply Administration ("GSA") Department.

12 Q. What are your duties as Assistant General Manager?

13 A. I report directly to the Assistant Vice President, and I am responsible

14 for implementing gas planning, gas purchasing and gas accounting

15 policies of the GSA Department.

16 Q. Summarize your education and prior work experience.

17 A. I received a Bachelor of Science Degree in Civil Engineering from the

18 State University of New York at Buffalo in 1991. I was hired by

19 Distribution in February 1992 as a Management Trainee in the Risk

20 Management-Environmental Affairs Department. I received my

21 Certified Hazardous Materials Manager ("CHMM") certification

22 through the Institute of Hazardous Materials Management. During

23 2000 I transferred to the Energy Services Department where I

1 received my certification as a Chartered Industrial Gas Consultant
2 through the Gas Research Institute. In October 2004 I was
3 transferred to GSA. I was recently promoted to my current position in
4 March 2016.
5 Q. Have you previously testified before the New York State Public
6 Service Commission ("Commission" or "NY PSC")?
7 A. No.
8 Q. Have you testified before any other commission?
9 A. Yes, I have testified before the Pennsylvania Public Utility
10 Commission in several purchase gas cost proceedings.
11 Q. Mr. McAvoy, please state your business address.
12 A. My business address is 6363 Main Street, Williamsville, New York,
13 14221.
14 Q. By whom are you employed and in what capacity?
15 A. I am employed by Distribution as Assistant General Manager within
16 the GSA Department.
17 Q. What are your duties as Assistant General Manager?
18 A. I manage gas supply/transportation/storage functions including
19 strategies, operations, contracting, planning and administration.
20 Q. Summarize your education and prior work experience.
21 A. I received a Bachelor of Science Degree in Mechanical Engineering
22 from the State University of New York ("SUNY") at Buffalo in 1982. I
23 received a Masters in Business Administration from the SUNY at

1 Buffalo in 1984. I am a member of the Alberta Northeast Gas,
2 Limited ("ANE") customer group and serve on the ANE budget
3 committee.
4 In September 1986, I joined Distribution as a Supervisor in
5 Distribution's Energy Services Department. I was transferred and
6 promoted in 1988 to Distribution's Gas Measurement Department as
7 a Junior Engineer and in 1992 was promoted to Department
8 Manager. I was transferred to Distribution's Gas Control Department
9 as Manager of Transportation and Exchange ("T&E") in 1993 and
10 was promoted to Director of T&E in 1997. In 2003, I was promoted to
11 Assistant General Manger in Distribution's GSA Department.
12 Q. Have you previously testified before the Commission?
13 A. No.
14 Q. Have you testified before any other commission?
15 A. Yes, I have testified before the Pennsylvania Public Utility
16 Commission and Canada's National Energy Board.
17 Q. Mr. Michalski, please state your business address.
18 A. My business address is 6363 Main Street, Williamsville, New York,
19 14221.
20 Q. By whom are you employed and in what capacity?
21 A. I am employed by Distribution as Assistant General Manager within
22 the GSA Department.
23 Q. What are your duties as Assistant General Manager?

1 A. I manage the implementation of Distribution's gas capacity, end-user
2 transportation and local production planning policies.
3 Q. Please summarize your education and prior work experience.
4 A. I received a Bachelor of Science Degree in Civil Engineering from the
5 State University of New York at Buffalo in 1978. I received my New
6 York State Professional Engineering License in March 1983. I
7 received a Masters of Business Administration from Canisius College
8 in May 1988. I am a member of the Independent Oil and Gas
9 Association of New York and the Pennsylvania Independent Oil and
10 Gas Association.
11 In June 1978, I joined Distribution as a Management Trainee. I
12 was transferred and promoted in December 1978 to Distribution's
13 Operations-South as a Junior Engineer. In December 1981, I was
14 transferred to Distribution's Energy Services Department and
15 promoted in 1982 to Assistant Engineer. In September 1985, I was
16 transferred to National Fuel Gas Supply Corporation's ("Supply" or
17 "NFGSC") Interstate Marketing Department and promoted in 1986 to
18 Director of Market Information. I transferred to Supply's Gas Control
19 Department in June 1987 as Director of Market Information. In
20 November 1988, I was promoted to Manager Contract Administration
21 in Supply's Contract Administration Department. In April 1993, I
22 transferred to Distribution as Assistant General Manager of
23 Distribution's GSA Department.

1 Q. Have you previously testified before the Commission?

2 A. No.

3 Q. Have you testified before any other commission?

4 A. Yes, I have testified before the Pennsylvania Public Utility
5 Commission in several purchase gas cost proceedings.

6 Q. What is the purpose of the Gas Supply Administration Panel
7 testimony?

8 A. The purpose of our testimony is to explain Distribution's gas
9 purchasing practices, as required by Public Service Law §66-e (2)
10 and Part 61.3 (d)(6) of the Commission's rules and regulations as
11 well as how the Department complies with the rules that govern
12 transactions between Distribution and its marketing affiliate.

13 **Capacity Reserved for Customers**

14 Q. Please describe how gas supplies are brought to Distribution.

15 A. Distribution maintains contracts for firm, long term, transportation and
16 storage capacity on Supply and on pipelines upstream of Supply that
17 include Dominion Gas Transmission ("DTI" or "Dominion"), Empire
18 Pipeline, Inc. ("Empire"), Honeoye Storage Corporation ("HSC"),
19 Tennessee Gas Pipeline ("TGP") and Transcontinental Gas Pipeline
20 ("Transco" or "Transcontinental"), to meet the gas supply
21 requirements of its firm sales and transportation customers.
22 Approximately only 5% of Distribution's annual deliveries to its
23 customers are sourced from local production attached directly to

1 Distribution's system. About 95% of Distribution's deliveries originate
2 from gas supplies attached to pipelines upstream of Supply or to
3 Supply itself. Distribution relies to a great extent on Supply's
4 transmission system to receive gas from pipelines upstream of its
5 system and in turn make redeliveries to Distribution's many non-
6 contiguous delivery systems. Distribution is also dependent on
7 Supply for the transmission of its gas supplies from Supply's storage.
8 Supply's storage and transmission facilities are used to receive gas
9 delivered to Supply via the pipelines upstream of Supply for
10 Distribution's account during periods of low customer demand and
11 are used to deliver gas to Distribution during the winter when
12 demands exceed flowing gas supplies being delivered via the
13 upstream pipelines. This allows Distribution to maintain a high load
14 factor on its upstream pipeline capacity resulting in lower pipeline
15 costs and a more favorable purchasing pattern with its suppliers.
16 Exhibit ___ (GSA-1), Schedules 1, 2 and 3, illustrate
17 Distribution's dependence on Supply's system. In Schedule 1, the
18 shaded areas identify Distribution's market areas. Schedule 2 shows
19 the major transmission lines of Supply. Distribution receives gas from
20 Supply at just less than 400 delivery points in New York and
21 Pennsylvania.
22 Schedule 3 demonstrates how the facilities of Supply
23 interconnect Distribution's facilities with the upstream pipelines that

1 deliver gas to New York customers. The colored lines are the major
2 transmission lines of the upstream pipelines that Distribution utilizes
3 to serve its western New York customers. The blue lines represent
4 major transmission lines of Supply that interconnect Distribution's
5 facilities and customers with the facilities of the upstream pipelines.
6 Exhibit ___ (GSA-2) shows Distribution's upstream pipeline
7 transportation and storage contracts used to meet its firm
8 requirements on a Design Day equivalent to 74 Heating Degree Days
9 ("HDD").
10 Q. Provide details of any plans to make significant changes to pipeline
11 transportation and storage capacity assets.
12 A. Distribution has been replacing its pipeline transportation capacity in
13 Canada that was used to source gas supplies at the Dawn Hub with
14 short-haul capacity from the Marcellus and Utica Shales in the U.S.
15 Northeast market area ("market area") on TGP from Zone 4 and on
16 Empire from Jackson, Pennsylvania adjacent to the New York State
17 border. Capacity on TGP and Empire provides firm delivery capacity
18 to the northernmost portion of Distribution's system. Distribution's
19 two remaining firm transportation contracts with TransCanada
20 Pipelines, Ltd ("TransCanada") that provide 10,141 Dth/day and
21 14,970 Dth/day will terminate on October 31, 2017 and on October
22 31, 2020, respectively.

1 Distribution has no other plans to make significant changes,
2 such as large increases or decreases to the overall quantity of its
3 pipeline and storage capacity assets; however, Distribution will make
4 adjustments on a case-by-case basis to its pipeline and storage
5 capacity as necessary from time-to-time.
6 Q. Provide a description of any new pipeline or storage assets that will
7 be acquired in the next five calendar years, including any projects
8 filed at the Federal Energy Regulatory Commission ("FERC") or for
9 which a precedent agreement has been submitted.
10 A. Distribution has no plans at this time to acquire any new pipeline or
11 storage assets in the next five calendar years.
12 Q. Include a description of any construction needed to accept deliveries
13 from the new pipeline or storage assets, and whether such
14 construction will be done solely by the Company or with partners.
15 A. Although no new pipeline or storage assets are anticipated to be
16 acquired at this time, from time-to-time Distribution requests
17 additional points of delivery from NFGSC in order to serve new and/or
18 existing customers. Such construction is typically carried out by
19 NFGSC and Distribution as required, and if necessary, by an
20 applicable pipeline capacity provider upstream of NFGSC, on a case-
21 by-case basis.
22 Q. Describe any potential natural gas transmission projects subject to
23 Article VII of the Public Service Law that may be filed in the next five

1 years.

2 A. Distribution is proposing in this proceeding to accelerate bare steel
3 transmission line replacements. These projects could exceed one-
4 mile in length and may require an Article VII filing. Specific projects
5 will be identified upon approval of the Company's proposal.

6 Q. Indicate whether the Company has been approached by other entities
7 about connecting pipelines, wells, or storage facilities directly to the
8 Company's distribution system, including high pressure transmission
9 lines owned by the Company and within the service territory, and
10 include a description of any such facilities currently attached to the
11 Company's facilities.

12 A. Local producers, including local production gathering systems, from
13 time-to-time, at their discretion, request new interconnections with
14 Distribution to deliver local production gas to Distribution's system.
15 Distribution currently maintains approximately 970 local production
16 meters that deliver into Distribution's system approximately 5% of its
17 gas supply throughput. Distribution's system is primarily supplied with
18 gas delivered to its facilities through transmission and storage
19 capacity on its affiliate, Supply, that in turn is connected to other
20 pipelines upstream of Supply. Distribution has otherwise not been
21 approached during the Historic Period by other entities about
22 connecting pipelines or storage facilities directly to the Company's
23 distribution system, including high pressure transmission lines owned

1 by the Company and within the service territory.

2 Q. What is the Company's current forecast/planning horizon for supply
3 and capacity purposes?

4 A. Distribution utilizes, and updates annually, a five-year planning
5 horizon for supply and capacity purposes. This is a reasonable
6 timeframe given the relative stability in the Company's customer base
7 over the years. A five-year time frame coincides with typical capacity
8 renewal term extensions for pipeline capacity that does not
9 automatically roll forward on a year-to-year basis.

10 Q. What reserve margin assumptions are utilized for design weather
11 forecasts and capacity requirement determinations? Provide all
12 calculations and/or studies used to develop the reserve margin
13 assumptions.

14 A. Distribution's Design Day forecast for its capacity requirement into its
15 system for the winter of 2015-2016 is 804,138 Dth/day. Distribution
16 has 810,347 Dth/day of firm transportation capacity into its system.
17 Therefore, its reserve margin or "Contingency Capacity" is currently
18 6,209 Dth/day, which is approximately 0.8%. Distribution maintains
19 sufficient capacity to meet the requirements of its sales customers
20 and its small volume transportation customers on a 74 HDD day with
21 a mean temperature of -9 degrees Fahrenheit. In addition,
22 Distribution maintains capacity to provide balancing service for its
23 larger volume transportation customers and for local production

1 attached to its system that is primarily used by its transportation
2 customers.
3 Distribution requires Contingency Capacity to enhance its ability
4 to maintain service to its customers should there be a capacity or
5 supplier failure or a force majeure instance or if the system
6 experiences load requirements that exceed the forecast Design Day.
7 Historically, Distribution's Contingency Capacity for the winter of
8 2007-2008 Design Day 2008 was 31,664 Dth/day, which was
9 associated with a Design Day forecast for its capacity requirement
10 into its system of 732,378 Dth/day. Therefore, its reserve margin or
11 Contingency Capacity at that time was approximately 4.3%.
12 For the winter of 2017-2018 Distribution's Design Day forecast
13 for its capacity requirement into its system will be 796,826 Dth/day.
14 Distribution plans to maintain its 810,347 Dth/day of firm
15 transportation capacity into its system. Therefore, its Contingency
16 Capacity at that time is forecast to be 13,521 Dth/day, which will be
17 approximately 1.7%.
18 Attached Exhibit ___ (GSA-3) titled "National Fuel Gas
19 Distribution Corporation-NY Forecast Design Day Requirements and
20 Contingency Capacity Summary" presents the requisite calculations
21 to show Distribution's level of Contingency Capacity.
22 Attached Exhibit ___ (GSA-4) titled "Extrapolated 74 HDD Study
23 – NY" presents total throughput on gas days 15 Degrees Fahrenheit

1 and colder into Distribution-NY's system for all sales and
2 transportation customers, extrapolated to what would have been
3 expected on a 74 HDD day. These are the values represented by the
4 green diamonds. The stacked blue and red bars show the total
5 requirements forecast for all sales and transportation customers and
6 the available Contingency Capacity respectively. The need for
7 Contingency Capacity is demonstrated by the numerous occasions
8 that projected system requirements would have exceeded forecast
9 requirements and Contingency Capacity combined.
10 Q. Describe the capacity that Distribution retains to ensure that
11 temperature variability and peaking requirements of the system are
12 served?
13 A. Distribution retains pipeline transportation and storage capacity on
14 NFGSC as summarized in Exhibit ___ (GSA-5) to balance the
15 requirements of its sales and its supplier-aggregated rate schedule
16 ("STBA")[1] small and large volume transportation customers, daily
17 metered customers, and to ensure the full delivery of the local
18 production that delivers into Distribution's system for its transportation
19 customers and to provide a quantity of Contingency Capacity. For
20 the sales and STBA customers, this provides enough capacity to
21 serve their load requirements associated with 12 HDD on a Design

1 Tariff No. 8, Service Classification No. 19, Supplier Transportation, Balancing and Aggregation.

1 Day. For local production this provides a quantity equal to
2 approximately 35% of its peak delivery capability because local
3 production has demonstrated a production reliability factor of 65% on
4 average during the past several winters. These retained capacity
5 requirements can change over time, as can the capacity contracts
6 that Distribution uses to serve them. The Supply Enhanced Storage
7 Service ("ESS") capacity serves temperature swing load, which
8 results from the variance between the predicted and actual weather.
9 The Supply Firm Storage Service ("FSS") contracts provide 588,700
10 Dth of Maximum Storage Capacity ("MSQ") and 15,420 Dth/day of
11 Maximum Daily Withdrawal Quantity ("MDWQ"). All of the storage
12 gas is delivered to Distribution via retained Supply Enhanced Firm
13 Transportation ("EFT") capacity. It is very important for Distribution to
14 control storage deliveries associated with extreme peak days so that
15 the system can efficiently serve operational requirements such as
16 extreme peak hourly demand.
17 Q. Given that the Company retains this transportation and storage
18 capacity, what quantity of capacity do suppliers need to obtain to
19 meet their peak-day obligations?
20 A. Pursuant to Rate Schedule STBA, suppliers are currently required to
21 have upstream pipeline and storage capacity that is sufficient to
22 deliver enough gas supplies to serve their customer requirements
23 only up to 62 HDD. The deliverability necessary to meet the

1 requirements above 62 HDD is provided for the suppliers by the
2 Company using the retained transportation and storage capacity
3 described above. Suppliers "make up" any such gas supplies
4 provided to their customers on a day colder than 62 Degree Days by
5 returning gas supplies to Distribution on the next day or days that are
6 warmer than 62 HDD.
7 Q. Describe how transportation customer imbalances are tracked by the
8 Company.
9 A. Transportation customer imbalances are equal to the differences
10 between the volumes used by the customers and the volumes, net of
11 Distribution's retainage percentage, delivered by their suppliers to
12 Distribution's system. Imbalances are aggregated at the supplier
13 level.
14 Q. Describe how and when imbalances are reconciled.
15 A. Imbalances can be traded between suppliers. Any imbalances that
16 remain after such trading are ultimately cashed out monthly by the
17 Company, based on a market price.
18 Q. Describe by customer class the process and procedures that the
19 Company uses to identify imbalances and to assign responsibility for
20 them.
21 A. Imbalances are cashed out on a monthly basis for monthly metered
22 customers and on a daily basis for daily metered customers.

1 Q. Describe how imbalance penalties are assessed, by month, by
2 customer.
3 A. Imbalance penalties are reflected in the price of the volumes sold to
4 marketers as a result of Daily Delivery Quantity ("DDQ") deficiencies.
5 Q. With respect to the Company's retail access program, discuss any
6 problems or issues arising from implementation of the Commission's
7 August 30, 2007 and March 28, 2008 Mandatory Capacity Release
8 Orders (in Case 07-G-0299) and FERC Order 712.
9 A. The Company has not experienced any problems or issues arising
10 from implementation of the Commission's August 30, 2007 and
11 March 28, 2008 Mandatory Capacity Release Orders (in Case 07-G-
12 0299) and FERC Order 712.
13 Q. List the pipelines and allocation percentages being utilized for the
14 mandatory assignment of capacity.
15 A. The pipelines and allocation percentages being utilized for the
16 mandatory assignment of capacity, effective April 1, 2016, include:
17 - Supply EFT capacity is assigned equal to 100% of the
18 quantity that transportation customers require to meet their
19 design peak requirement equivalent to 62 HDD, delivered into
20 the Company's city-gate, and
21 - Capacity into Supply is also assigned, typically as follows:
22 TGP – Firm Transportation capacity "FT-A" = 57%* and
23 Supply – ESS = 43%*

1 * Customers with higher load factors will receive less Supply
2 ESS capacity and more TGP FT-A capacity
3 Q. Provide a comparison between the Company's Weighted Average
4 Cost of Capacity ("WACOC") and the charges paid by marketers and
5 direct customers for released capacity.
6 A. The following table presents a comparison between Distribution's
7 WACOC and the charges paid by marketers and direct customers for
8 released capacity for the period April 2014 through April 2015.
9 Column A lists Distribution's WACOC. Column B lists the charges
10 paid by marketers and direct customers for released capacity.
11 Column C reflects the difference between the two columns (A – B).

	A	B	C
Month	Distribution WACOC	Released Capacity	Difference: A -B
Apr-14	$9.8099	$9.8099	$0.0000
May-14	$9.8118	$9.8099	$0.0019
Jun-14	$9.8190	$9.8099	$0.0091
Jul-14	$9.8215	$9.8099	$0.0116
Aug-14	$9.8498	$9.8099	$0.0399
Sep-14	$9.8419	$9.8099	$0.0320
Oct-14	$9.8389	$9.8099	$0.0290
Nov-14	$10.0196	$9.8099	$0.2097
Dec-14	$10.0186	$9.8099	$0.2087
Jan-15	$10.0046	$9.8099	$0.1947
Feb-15	$10.2187	$9.8099	$0.4088
Mar-15	$10.1958	$9.8099	$0.3859
Apr-15	$9.4025	$9.4025	$0.0000

Q. What process, if any, is utilized to true-up any differences?

A. Differences between Distribution's WACOC and the charges paid by marketers are not trued up as they may be either positive or negative and are typically not significant.

Distribution updates the calculation of its WACOC each April. The weighted average cost of the segments of Mandatory Upstream Transmission Capacity ("MUTC") that are released to the marketers for this initial month of April is set equal to Distribution's WACOC. In subsequent months, unless Distribution's WACOC changes by more than 5% from the initial April calculation, the MUTC release rates do not change.

If Distribution's WACOC does change by more than 5%, Distribution will update and reset its WACOC to the new average effective with that month and accordingly adjust the MUTC release rate(s) in order to achieve the same weighted average cost.

Q. Indicate any expected changes to the amount of Grandfathered Upstream Transmission Capacity ("GUTC") and Grandfathered Intermediate (Supply) Transmission Capacity ("GITC") used by marketers to serve retail customers.

A. The amount of GUTC and GITC used by marketers, on a combined basis, is currently 72,941 Dth/day, down from 73,861 Dth/day the previous year. Although Distribution has experienced small annual declines, significant changes in the near future are not anticipated.

1 **Least Cost Purchase Policy & Gas Price Risk Management**

2 Q. Please provide a general description of the Company's gas
3 purchasing strategy including an identification of the amount of
4 Canadian, domestic gas and LNG purchases.

5 A. The Company continually evaluates its market needs and available
6 opportunities to adjust its pipeline and storage capacity mix and gas
7 source diversity, seeking to achieve the least cost for customers
8 without compromising reliability. The mix has evolved over the last 5
9 years as Northeast shale production within the Appalachian basin
10 has grown to over 20 BCF/day. The Company's portfolio of pipeline
11 capacity has evolved from long-haul capacity paths originating in the
12 Southwest production region ("region") to a mix of long-haul capacity
13 paths and short-haul capacity paths originating in the market area.
14 As this capacity mix has evolved, so have the Company's purchases.
15 For the test year, 97% of total supplies were purchased at market
16 area receipt points and 3% from the traditional region. None of the
17 supplies were purchased in Canada or from LNG terminal
18 interconnects. For the first and subsequent two rate years, the
19 Company anticipates that nearly all of the supplies will be purchased
20 in the market area unless significant changes occur in the natural gas
21 market.

22 Q. Explain the types of contracts and associated contract flexibility the
23 Company utilizes for gas purchases.

1 A. The Company purchases gas on a term basis (delivery period greater
2 than one month) and a spot basis (delivery period equal to, or less
3 than, one month).
4 For term purchases, the Company utilizes either the Company's
5 Master Gas Purchase Contract or the North American Energy
6 Standards Board ("NAESB") contract, and the associated contract
7 provisions primarily for firm winter supplies to ensure reliable
8 deliveries. The Company negotiates liquidated damages language in
9 its term contract provisions in order to encourage suppliers to deliver
10 the contracted-for volumes. Pursuant to the Company's Gas Cost
11 Management Plan ("Plan"), the contracts for term gas supplies may
12 include forward priced, monthly index and daily index purchases.
13 These term supplies may contain firm baseload obligations or provide
14 the Company with monthly and/or daily take or release flexibility of
15 firm deliveries. These firm arrangements may contain demand
16 charges. The demand charge paid reflects a payment for the firm
17 delivery commitment by those suppliers. The take or release
18 contracts allow the Company to contract for gas supplies and avoid
19 take-or-pay provisions and minimum commodity requirements.
20 The Company purchases spot gas from time to time. The term
21 "spot" refers to gas supplies purchased on a daily or month-to-month
22 basis at negotiated market prices such as NYMEX Settlement with a
23 basis, Cash or published indices. Spot purchases are generally

1 entered into under the standardized natural gas industry contracts
2 developed by the Gas Industry Standards Board ("GISB") or NAESB.
3 The commercial terms of each purchase are specified and confirmed
4 by both parties using a standardized GISB or NAESB transaction
5 confirmation. Spot contracts are used primarily for daily or monthly
6 spot purchases when flexibility is required and the added reliability
7 obtained with a long-term firm contract is less of an issue.
8 Q. Please describe how the Company plans its reliance on firm gas,
9 spot gas, swing gas, etc?
10 A. The Company has the ability to serve 100% of its Design Day winter
11 requirements with firm gas supplies via seasonal take or release
12 supply agreements with suppliers. These agreements provide the
13 Company with the ability to call upon firm supplies for the prompt
14 month or prompt day during the winter season. Based on forecasted
15 demand variability and system operational criteria for each month, the
16 Company develops a monthly purchase plan incorporating the Plan.
17 To implement each month's purchase plan, the Company will elect to
18 baseload a specified quantity of the monthly supplies, priced at a
19 monthly index, NYMEX with a basis adjustment and cash; and elect a
20 daily call option on the remaining seasonal agreements. The
21 Company utilizes the daily call option, priced at a daily index or cash
22 price, throughout the month to respond to daily market demand
23 variability.

1 Q. Are there any triggers that prompt the Company to purchase daily
2 spot gas?
3 A. To the extent that winter conditions are not extreme, the take or
4 release flexibility associated with most firm winter gas supplies
5 provide the Company an opportunity to evaluate daily purchase
6 options to replace firm gas with lower cost supplies in the daily spot
7 market. During the summer season when delivery reliability is of less
8 importance the Company's planned purchases are procured
9 predominately in the monthly and daily spot markets.
10 Q. What are the typical pricing terms and indices of the Company's
11 contracts?
12 A. As described earlier, the pricing terms of the Company's term and
13 spot purchases include a diversified mix of forward prices, monthly
14 and daily published indexes and cash prices. The mix of these
15 pricing terms is specified by the Plan for the applicable season.
16 Q. At what receipt points does the Company typically purchase its
17 supplies?
18 A. The Company purchases the majority of its supplies at liquid receipt
19 points. These liquid receipt points include discrete physical meters,
20 logical pool meters, and trading hubs. However, some local
21 production supplies are purchased at the producer's meter or a
22 processing plant meter that is not as liquid as a large trading hub.
23 Liquid purchase points used by the Company include the traditional

1 gulf coast and market area pooling points on TGP, Transco and DTI.
2 The Company has also identified the Millennium interconnect with
3 Empire at Corning as an emerging liquid receipt point. It's important
4 to note that all of the Company's firm transportation contracts provide
5 primary receipt or in-path access to liquid receipt points.
6 Q. Explain the effects that new gas supply sources have had on the
7 Company's current (and long-term) purchasing strategy including
8 historical volumes of gas purchased from the Marcellus, Rockies and
9 any other region?
10 A. Market area shale, including Marcellus and Utica shale production,
11 has grown steadily since 2005 and accounts for approximately one
12 third of the US total daily production. This production growth has led
13 to lower NYMEX prices and dramatically discounted market area
14 prices. As a result of these prices, the Company's purchase of
15 market area supplies has steadily grown to now account for over 95%
16 of the total purchases. The remaining balance of the Company's
17 purchases are sourced from traditional domestic production basins
18 including the Gulf of Mexico and the Rockies. Exhibit ___ (GSA-6)
19 provides a graphical summary of that trend. To the extent the current
20 economic market conditions remain intact and market area
21 production does not dramatically decrease, the Company will
22 continue to purchase nearly all of its supplies in the market area.

1 Regarding Rockies purchase volumes, the Company did
2 acquire limited volumes of supplies via Rockies Express Pipeline
3 deliveries from February 2010 through January 2012. Those monthly
4 volumes ranged from 0% to 20% of the total monthly purchases
5 during that period. The emerging Marcellus shale production
6 supplanted further Rockies sourced purchases.
7 Q. In light of the effects of Marcellus Shale area production, since what
8 was once classified as a market area may be reclassified as
9 production area, will the Company's strategy for using storage assets
10 change?
11 A. Strategy for using storage capacity remains unchanged. The
12 Company's storage portfolio that includes storage capacity on Supply
13 and DTI is located in the market area near the Company's customers.
14 This storage capacity will continue to be used to serve peak winter
15 demand, as a hedge against winter price volatility and to improve
16 utilization of pipeline capacity during the summer storage fill season.
17 Q. Does the Company foresee changes to its analysis for utilization of
18 long-haul capacity versus short-haul capacity?
19 A. The Company applies the same analysis for all purchase and
20 contract renewal decisions. Factors considered include operational
21 requirements, reliability concerns, commodity and transportation
22 costs, capacity release values, long term supply viability and basin
23 diversity. The Company employs the Ventyx SENDOUT II linear

1 program model to assist in evaluating the economic impact of various
2 seasonal and monthly supply options. For daily purchases, the
3 Company evaluates the daily cash markets for least cost purchase
4 alternatives.
5 Q. Regarding basin diversification, indicate whether the Company plans
6 to make any significant changes to its sourcing of natural gas supply.
7 A. The Company relies on diversified pipeline assets reaching back to
8 multiple production basins to ensure that adequate gas supplies are
9 available. As previously described, the Company's pipeline asset mix
10 has evolved over the last several years driven largely by the
11 emergence of prolific northeast shale gas supplies. Exhibit ___
12 (GSA-7) compares the pipeline asset mix of Winter 2012 to Winter
13 2015. Over that four year period, the Company's pipeline assets
14 with northeast receipt points have grown from one third to over two
15 thirds. Similarly, the Company's purchases have shifted to greater
16 quantities of market area purchases as illustrated in Exhibit ___
17 (GSA-6).
18 The Company's level of supplies purchased from different
19 supply sources is determined by multiple factors including customer
20 demand, regional system requirements, the Plan and market prices.
21 To ensure winter reliability, the Company enters into firm purchase
22 agreements at all of the receipt points associated with the upstream
23 firm pipeline capacity in addition to some firm citygate purchase

1 agreements. The majority of these firm winter purchase agreements
2 provide take-or-release flexibility that allows the Company to address
3 the aforementioned factors to reliably serve customers.
4 Q. How are changing supply sources utilized to achieve cost
5 diversification goals?
6 A. Cost diversification is primarily achieved through the Plan which is
7 achieved through a mix of pricing arrangements rather than the
8 location of the purchase. Maintaining access to multiple basins and
9 multiple receipt points within each basin provides supply source
10 diversification critical to ensure reliability. The Company seeks least-
11 cost optionality of the winter purchases to adequately serve customer
12 demand, deliver to specified load pockets and mitigate price volatility.
13 Q. Please explain the Gas Cost Management Plan.
14 A. The Plan summarizes the different gas purchase specifications the
15 Company uses to diversify pricing of the monthly gas supplies during
16 the summer and winter seasons. During the winter season, the Plan
17 diversifies pricing by prescribing that approximately 39% of required
18 seasonal supplies are served by storage withdrawals and 61% by
19 pipeline supplies. Of these pipeline supplies, 12% are forward price
20 triggered during the prior summer, 37% are priced at monthly index
21 and 12% at daily index. Combining storage and forward price
22 supplies provides ratepayers with summer price certainty for nearly
23 half of the winter supplies.

1 Beginning in 2015, the Company incorporated index price caps
2 in the forward price portion of the Plan. The Company executes
3 forward price transactions on predetermined days throughout the
4 summer period for firm winter delivery. Specifically, the forward
5 purchase quantities are split equally between quantities purchased at
6 a fixed price and quantities purchased at a monthly index with a cap
7 price.
8 During the summer season, the Plan specifies that the summer
9 supplies consist of 60% monthly index and 40% daily index for
10 serving market requirements and filling storage.
11 Q. Describe the goals of the Company's cost diversification efforts and
12 the metrics the Company will use to measure achievement of the
13 goals.
14 A. The Company has, for the past several years, purchased gas
15 pursuant to its Plan to reduce the effects of gas price volatility on its
16 sales customers. Exhibit ___ (GSA-8) is a copy of the current Plan.
17 The Plan has evolved as the Company has gained experience under
18 its Plan and to respond to the changes in the marketplace and
19 suggestions by Staff. The overall goal of the Plan however, is
20 unchanged, and that is to mitigate price volatility through price
21 diversification as instructed by the NY PSC in its Statement of Policy
22 Concerning Gas Purchasing Practices (Case 97-G-0600).

Q. Does the Company employ financial hedging methods that include financial swaps/future transactions or option transactions?

A. The Company does not employ any such financial hedges. All of the Company hedging employs physical gas transactions.

Q. Describe any "lessons learned" in the course of the Company's gas price mitigation efforts over the past year and whether the Company's hedging strategy has changed since then.

A. The Company's Plan mitigates volatility through price diversification. The Plan is not intended to "beat" the market. Price spikes experienced last year in capacity constrained regions confirm that the most effective hedge against price volatility is maintaining adequate storage and upstream capacity.

At the suggestion of Staff, the hedging strategy for winter 2015-2016 was modified to include physical price caps. Approximately 50% of forward priced gas (6% of system requirements) was purchased at an index price not to exceed $5 per Dth. The Company intends to continue purchasing similar price caps for the upcoming rate years.

Q. How does the Company measure volatility and determine the success or failure of the Plan?

A. Although volatility is not formally calculated, a chart indicating the impact of changing commodity prices on customer bills for eight years is reviewed by executives on a monthly basis (Exhibit ___ (GSA-9)).

1 The success of the Plan is based on its ability to stabilize
2 prices. This is accomplished by creating a diversified portfolio of
3 market priced supplies that reflect the average cost of gas over an
4 extended period of time.
5 Q. Please provide actual versus planned price hedging performance for
6 winter 2014-2015. Include separate quantities for each pricing
7 category.
8 A. Exhibit ___ (GSA-10) summarizes planned versus actual price
9 hedging performance for winter 2014-2015.
10 Q. Does the Company monitor its volatility mitigation program? Please
11 discuss the internal reporting, oversight and audit structure.
12 A. Distribution's Plan is reviewed and approved by the Officer in charge
13 of the GSA Department prior to implementation. The Officer reviews
14 and approves all hedge transactions. Historical performance and
15 current physical hedge positions are reviewed monthly with senior
16 Officers.
17 Q. Provide the current level of natural gas supply used by the Company
18 to meet normal customer requirements and how that amount will
19 change in the rate year.
20 A. Generally, the Company utilizes its mix of pipeline and storage assets
21 to source adequate, reliable and least cost supplies of gas for the
22 ratepayers. The Company structures its purchases to meet the
23 customers' daily, winter season, peak day and annual requirements.

1 For the 12 month period ending October 31, 2015, the Company
2 forecasted its annual sales demand at 47.8 bcf, of which 35.5 bcf
3 was forecasted for the November through March winter period.
4 Forecasts for the 12 month period ending October 31, 2018, inclusive
5 of the rate year, reflect a slight decrease in annual and winter
6 demands of 47.3 BCF and 35.1 BCF, respectively. Exhibit ___ (GSA-
7 11), submitted annually to the NY PSC, provides further forecast
8 details.
9 Q. Provide how the level of term supplies vs. spot supply purchases is
10 determined and implemented.
11 A. As previously discussed, the Company utilizes term contracts and the
12 associated contract provisions primarily for firm winter supplies to
13 ensure reliable deliveries. However, the Company utilizes the
14 flexibility offered by its term purchases to incorporate lower cost spot
15 supplies into its winter supply portfolio. For each winter month, the
16 Company evaluates its monthly option to forego select monthly
17 deliveries on certain traditional term supplies and replace those
18 deliveries with more cost effective monthly spot supplies. To the
19 extent the Company elects to purchase those spot supplies, it
20 maintains a daily call option with respect to its term contracts.
21 Additionally, the Company will utilize term contracts to enter into
22 Asset Management Arrangements or baseload purchases during the
23 summer period.

1 Spot contracts are used primarily during the non-winter months
2 when reliability obtained with a long-term firm contract is less of an
3 issue.
4 For the winter period from November 2014 to March 2015 the
5 Company arranged for 100% of its winter purchases utilizing term
6 contracts. During the winter, the Company elected to purchase lower
7 cost spot monthly supplies for 26% of its winter purchases and
8 maintained a daily call option on those replaced term contracts in the
9 event that those spot suppliers failed to deliver supplies.
10 For the test period of January 2015 to December 2015, term
11 purchases represented 61% of the system supplies and spot
12 purchases represented 39%.
13 Q. Indicate how different pricing scenarios and terms are utilized to
14 achieve cost diversification goals.
15 A. Cost diversification is achieved through the Plan discussed
16 previously.
17 **Indigenous Gas Supplies**
18 Q. Has the Company purchased indigenous natural gas production?
19 A. Yes, the Company has purchased indigenous production directly into
20 its system. Below is a monthly summary of those purchased volumes
21 for the last three years.

Distribution Local Production Volume (Dth)			
Month	**2015**	**2014**	**2013**
January	1,638	1,800	1,612
February	1,046	1,862	1,245
March	1,837	1,765	1,284
April	1,616	2,151	1,147
May	1,975	2,105	973
June	2,155	1,964	1,806
July	1,841	2,001	1,598
August	2,307	2,217	2,266
September	1,957	2,036	1,753
October	1,845	1,742	2,358
November	1,495	1,710	1,922
December	3,161	2,004	2,135
Total	22,873	23,357	20,099

Q. Describe what steps the Company is taking to capture the benefits of connecting indigenous gas supplies directly to its distribution system, where possible.

A. The Company supports, and is active in, the local production community through its involvement with the New York Independent Oil & Gas Producer organization. New or additional local production is connected to the Company's system at the request of local producers.

1 Q. Is the Company proposing any modifications with respect to how it
2 receives local production into its pipeline system facilities?
3 A. Yes. The Company is proposing that local production must be able
4 to deliver a minimum of one thousand cubic feet ("MCF") per day into
5 its system at any local production meter point. Maintaining meters
6 that receive lesser quantities is not efficient or cost effective and
7 consumes valuable Company resources that are needed to serve
8 customers. Currently Distribution has 973 local production meters
9 that receive gas into its system in New York State. Approximately
10 191 of these meters received less than 1 MCF per day on average
11 over the twelve month period ending December 31, 2015.
12 Q. What option would local producers have to maintain deliveries of gas
13 to Distribution from well(s) upstream of meters that would be removed
14 pursuant to this proposal?
15 A. Local producers would be able to connect such well(s) to other local
16 production meters that deliver one MCF per day or more to
17 Distribution's system or to other operators' systems that would agree
18 to accept such local production.
19 Q. What impact would this have on the monthly receipt facility charge
20 that the Company collects for local production receipt points?
21 A. Currently Distribution assesses all local producers an average fee of
22 $40.00 per meter per month, which represents a portion of the cost to
23 maintain and administer the receipt of local production at a local

1 production receipt point. The Company proposes to eliminate its
2 monthly receipt facilities fee and has reflected this in its revenue
3 requirement and proposed tariff.

4 **Mitigation of Fixed Costs and Asset Optimization**

5 Q. Provide a description of the Company's plans and strategy with
6 respect to off-system sales, capacity release and streaming
7 arrangements and indicate whether any off-system sales, capacity
8 release or streaming arrangements extend beyond the current rate
9 year, and when they end.

10 A. The Company's strategy has, and will remain, to optimize gas supply
11 purchases and pipeline and storage capacity utilization to minimize
12 ratepayer costs. The Company achieves this optimization primarily
13 through release of unutilized capacity and off-system sales activities.
14 The Company does not enter into streaming arrangements, defined
15 as allocating specific gas supplies and associated pricing to a
16 particular customer or customer group. There are no off-system
17 sales or capacity release arrangements extending beyond the current
18 rate year.

19 The demand for and value of capacity release and sales
20 opportunities will vary due to many factors, including time of year and
21 weather conditions; however, recent growth in natural gas-fired
22 electric generation resulting in significant summer pipeline throughput
23 has affected the summer release and sales markets. Traditionally, it

1 was expected that there would be greater demand for gas supplies
2 and capacity, along with greater margins and release credits, during
3 winter periods, particularly when weather was colder than normal.
4 Conversely, extremely warm summer weather that creates electric
5 cooling demand provides capacity release and sale opportunities.
6 Thus, there are a variety of factors that affect the levels of off-system
7 sales and capacity release. In light of these changing variables, the
8 projected level of capacity release and off-system sales are difficult to
9 ascertain.
10 If the Company experiences normal or warmer than normal
11 temperatures in early or late winter, off-system sales can be made
12 and capacity can be released without jeopardizing service to firm
13 customers. All releases are awarded to parties with recall rights so
14 that if unexpected circumstances arise during the release period, the
15 Company may recall the capacity for use.
16 The first step in determining whether capacity can be released
17 or an off-system sale can be made is to determine whether there are
18 gas supplies and/or capacity that will not be needed to meet the
19 requirements of customers. This determination requires
20 consideration not only of projected requirements of the Company's
21 customers but also of the need, at various times of the year, to fill
22 storage fields in order to meet peak and winter requirements of
23 customers.

1 While the Company reviews its requirements and available
2 capacity continually, a formal review is conducted prior to the
3 commencement of each calendar month to determine, in the
4 aggregate, whether the Company has firm gas supplies under
5 contract that will not be purchased during the month. If so, the
6 Company will seek to release capacity that it will not use during the
7 next 30-day period or less. The Company's process for making such
8 releases available is as follows: first, the Company sends an e-mail to
9 potential customers notifying them of available capacity to be
10 released. Interested customers then contact the Company to place a
11 bid. The Company may select a counterparty as the prearranged
12 bidder based on the initial bids. The Company generates a capacity
13 release offer and posts the release for bidding on the pipeline's
14 electronic bulletin board. The bidding period ranges from 1 hour for
15 day-to-day releases to a few days for longer term releases. To the
16 extent a release is posted indicating a pre-arranged bidder, that
17 bidder is given the right to match a higher bid submitted on the
18 bulletin board from any competing bidders.
19 When engaged in off-system sales, the Company may sell gas
20 at any point on its transportation and storage capacity upstream of its
21 capacity on Empire and NFGSC. There are two types of off-system
22 sales: Purchase for Resale and Weighted Average Commodity Cost
23 ("WACC") Sale.

1 Purchase for Resale transactions are those sales transactions
2 where an additional unscheduled purchase is made during the month
3 specifically for an off-system sale. Such purchases are considered to
4 be gas for off-system sales and the commodity cost of such purchase
5 will be assigned to off-system sales up to the volume of the purchase.
6 Such purchase may either be transported directly to the sale point via
7 idle but unreleased transportation capacity or via displacement of
8 system supply scheduled for delivery to the Company's NFGSC
9 capacity. Under a displacement scenario, the additional unscheduled
10 purchase is delivered to the Company's NFGSC capacity in a
11 quantity equal to the originally scheduled system supply delivery that
12 was displaced to make the sale. The Company ratepayer savings
13 equal 85% of the net revenues from Purchase for Resale
14 transactions, before taxes, over the commodity cost of the purchased
15 gas plus any variable transportation costs to deliver the gas to the off-
16 system customer.
17 WACC sales occur less frequently than Purchase For Resale
18 transactions, and are those sales typically conducted during days of
19 unexpected low system demand where the daily quantity of baseload
20 supplies for the month exceed the system demand. These sales are
21 valued at the monthly average commodity cost of all supplies
22 scheduled at the beginning of the month. The pricing terms for the
23 commodity cost of these gas supplies include but are not limited to:

first of month and daily index prices, NYMEX settlement prices and prices fixed in advance of the month of flow. The Company ratepayer savings equal 85% of the net revenues from WACC sales, before taxes, over the monthly average commodity cost of gas plus any variable transportation costs to deliver the gas to the off-system customer.

Q. Does the Company have plans to make significant changes to its off system sales practices?

A. The Company has no plans to significantly change its off system sales practices.

Q. Provide a detailed description of any existing asset management or asset optimization advisory agreements, as well as any such agreements being considered or planned by the Company.

A. The Company entered into asset management arrangements ("AMA") involving one or both of the Company's Transco firm transportation ("FT") contracts. Generally, these AMAs entailed the release of the entire path or path segments of the capacity to an asset manager and the asset manager delivering Leidy Line production gas supplies to the Company at the receipt meter, located at the NFGSC and Transco interconnection. The Company ratepayer savings equal 85% of the net revenues from the AMA transactions.

There were five discrete AMA transactions executed for the test year. Of the five transactions, two were for the winter 2014-2015

1 period, one for the summer 2015 period and two for the winter 2015-
2 2016 period. All five AMA transactions included release of capacity
3 and the purchase of gas supplies as described above.
4 The Company has recently entered into a similar AMA for the
5 summer 2016 period. The Company plans to seek and consider
6 offers from counterparties for future AMAs.
7 Q. Please summarize the revenues received over the last five years
8 from the Company's off-system sales and capacity release activities.
9 A. Exhibit ___ (GSA-12) shows the last five-years of margin associated
10 with non-migration capacity releases and off-system sales. The
11 Exhibit also tabulates the margin totals and those amounts allocated
12 to customers and the Company for both non-migration capacity
13 releases and off-system sales by fiscal year.
14 **FERC Intervention and Interstate Pipeline Costs and Issues**
15 Q. With regard to pipeline costs, how does Distribution review and test
16 the costs associated with its pipeline capacity?
17 A. Distribution actively represents its positions at the FERC, asserting its
18 interests as a local distribution Company in all cases where such
19 action is appropriate, including FERC rulemakings, generic
20 proceedings and the rate and certificate proceedings of upstream
21 pipelines on which Distribution holds capacity, including Supply. In
22 this regard, Distribution's Assistant Vice President, Assistant General
23 Manager, and Assistant General Counsel, as well as other regulatory

1 and gas supply personnel in the GSA Department and in the Rates
2 and Regulatory Affairs Department, are responsible for identifying
3 and/or reviewing proceedings at the FERC that affect or potentially
4 affect Distribution and its customers.
5 When such a proceeding is identified, Distribution intervenes
6 and participates to ensure appropriate representation of Distribution
7 and its customers. Such participation may include attending and
8 participating in customer meetings and public conferences,
9 presenting comments, or filing formal pleadings. As described more
10 fully below, Distribution also pursues issues in litigation where
11 appropriate.
12 Q. Please describe FERC regulatory proceedings the Company has
13 either intervened in or been involved with?
14 A. Distribution has specific capacity on the following interstate pipelines
15 to serve its New York end-users: Dominion, Empire, Supply, TGP
16 and Transco. In addition, Distribution holds capacity on
17 TransCanada, a Canadian pipeline which is subject to regulation by
18 the National Energy Board ("NEB"). Set forth in Exhibit ___ (GSA-13)
19 is a list of FERC proceedings in which Distribution participated during
20 the historical period. Distribution participates in Canadian regulatory
21 proceedings through ANE, a Canadian Company that represents
22 interests of northeastern U.S. utilities. In addition, as a member of
23 TransCanada's Tolls Task Force ("TTF") Distribution works with other

1 shippers and interested parties to seek consensus and resolution of
2 issues related to the tolls, tariffs and operations of TransCanada.
3 ANE and TTF efforts for the historical 12-month period ended
4 December 31, 2015 are described below.

5 **Individual Pipeline Proceedings at the FERC**

6 During the historical period, Distribution participated in the
7 following individual pipeline proceedings at the FERC.[2]

8 **Empire Pipeline, Inc.**
9 **Section Five Order- Docket No. RP16-300**

10 Although outside of the historical period, it is worth noting that
11 on January 21, 2016 the FERC issued an Order requiring Empire to
12 file a cost and revenue study with a derivation of rates. Pursuant to
13 the Order, a settlement conference has been scheduled before a
14 FERC appointed Settlement Judge on May 12, 2016. The Hearing
15 Order mandates the cost and revenue study include essentially all the
16 information Empire would be required to file in an NGA section 4
17 proceeding. Distribution contracts for 34,500 Dth/Day of capacity
18 with Empire and will be an active participant in the proceeding.

19 **National Fuel Gas Supply Corporation**
20 **Decoupled Storage Capacity Release Filing - Docket No. RP15-1100**

21 On August 6, 2012, the FERC approved a partial settlement of
22 Supply's general section 4 rate case in Docket No. RP12-88 ("RP12-

[2] In addition, Distribution filed its FERC Form No. 552: Annual Report of Natural Gas Transactions on April 22, 2015 and FERC Form No. 549D: Quarterly Transportation and Storage Report of Intrastate Natural Gas and Hinshaw Pipelines

1 88 Settlement").[3] Article X of the RP12-88 Settlement provided that
2 the participants would continue ongoing discussions regarding
3 certain enhancements that shippers requested to storage service
4 (*i.e.,* the decoupling of injection and withdrawal rights from storage
5 capacity rights, the development of firm injection rights in the winter
6 season, and the development of firm withdrawal rights in the summer
7 season). Supply agreed to prepare and provide a written analysis of
8 the impact of the aforementioned storage enhancement proposals on
9 its storage services/fields, and to include in that analysis a detailed
10 explanation of how such service enhancements would be
11 accomplished or, if they could not be accomplished, why that was the
12 case. If after the parties evaluated and discussed the written analysis
13 they agreed that one or more of the storage service enhancements
14 should be implemented on Supply's system, Supply would make and
15 support one or more tariff filings to implement the agreed-upon
16 storage service enhancement(s). Supply proposed tariff records
17 associated with storage service enhancements under Docket No.
18 RP13-299. The FERC issued its final letter order in Docket No.
19 RP13-299 on May 17, 2013 ("May 2013 Order"), wherein it approved
20 Supply's proposed tariff records associated with summer period
21 storage withdrawals but rejected the tariff records associated with
22 decoupled storage capacity releases, because Supply proposed that

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on February 19, 2015, May 5, 2015 and August 11, 2015.

1 the proposal contained in them take effect at some indefinite time in
2 the future in violation of FERC regulations. Nevertheless, the FERC
3 evaluated the rejected tariff records as though they were *pro forma*
4 and indicated that Supply would be permitted to file actual tariff
5 records identical to the *pro forma* tariff records no less than 30 or
6 more than 60 days in advance of the proposed effective date of the
7 tariff records.

8 On June 30, 2015, Supply submitted a filing at the FERC under
9 Docket No. RP15-1100 ("June 30 Filing") indicating that it had
10 completed the business system modifications required to implement
11 decoupled storage capacity releases and proposing tariff provisions
12 regarding decoupled storage capacity releases, in accordance with
13 the May 2013 Order, to become effective on August 1, 2015. In
14 Docket No. RP13-299, Supply agreed to perform an impact analysis
15 of decoupled releases and discuss possible tariff revisions after two
16 years of operating experience. The proposed tariff provisions require
17 Supply to provide the analysis and information on or before June 30,
18 2017, schedule a conference call with interested parties for a time no
19 later than September 30, 2017, and file any agreed-upon tariff
20 changes resulting from these discussions no later than November 15,
21 2017.

22 The FERC issued a letter order approving the June 30 Filing on

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[3] *National Fuel Gas Supply Corp.*, 140 FERC ¶ 61,114 (2012).

July 23, 2015.

National Fuel Gas Supply Corporation
Settlement in Lieu of a Rate Case - Docket No. RP15-1310

Article V of the RP12-88 Settlement required Supply to file a NGA Section 4 general rate case no later than January 1, 2016. On May 7, 2015, Supply posted a notice on its website indicating that it was undertaking discussions with customers and interested parties about the possibility of extending the comeback date of its RP12-88 Settlement. Supply subsequently engaged in settlement discussions with its customers, including Distribution, state commissions and consumer advocates and responded to their data requests. Supply met with active parties in Washington D.C. on June 16, 2015 and August 14, 2015. Following the August 14, 2015 meeting, parties exchanged settlement drafts and met in Washington D. C. on September 18, 2015 for final negotiations. On September 29, 2015, Supply submitted the final settlement for approval at the FERC under Docket No. RP15-1310 ("September 2015 Settlement"). The FERC issued a letter order approving the September 2015 Settlement on November 13, 2015.

The September 2015 Settlement provided for an immediate two percent reduction in Supply's base reservation, capacity, demand and deliverability rates, effective November 1, 2015. An additional two percent reduction will be made effective on November 1, 2016. The September 2015 Settlement also authorizes Supply to implement a

1 new tariff mechanism to recover pipeline safety and greenhouse gas
2 costs for costs associated with new legislation and regulatory
3 requirements issued after August 14, 2015. In addition, Supply also
4 agreed to update and share an earlier storage study regarding winter
5 season firm injection rights, including data through the 2015-2016
6 winter season, and discuss that study and potential related tariff
7 revisions with interested parties.
8 The September 2015 Settlement precludes Supply from filing a
9 new NGA Section 4 general rate case before September 30, 2017,
10 nor can it file any proposed Docket No. PL15-1 modernization tracker
11 mechanism to replace the pipeline safety and greenhouse gas
12 tracker until that date. The "comeback" date by which Supply is
13 required to file an NGA Section 4 general rate case is revised to on or
14 before December 31, 2019.
15 The two percent reduction in Supply's base reservation, capacity,
16 demand and deliverability rates will result in an annual gas cost
17 savings allocated to New York of approximately $950,000 in 2016.
18 The second two percent reduction will result in the annual gas cost
19 savings doubling in 2017.

20 **Tennessee Gas Pipeline Company, L.L.C.**
21 **Rate Case Filing - Docket No. RP11-1566**

22 On November 30, 2010, TGP submitted a rate filing to FERC in
23 Docket No. RP11-1566, pursuant to Section 4 of the Natural Gas Act.
24 After lengthy negotiations a settlement was reached between TGP

1 and its customers and ultimately approved by the FERC on
2 December 5, 2011 ("2011 Settlement"). Distribution continued to
3 address several issues associated with the 2011 Settlement during
4 the historical period.
5 Revenue Sharing Mechanism: The 2011 Settlement obligated
6 TGP to establish a "Revenue Sharing Mechanism" for the term of the
7 settlement (through October 31, 2015) to share with Eligible
8 Customers seventy-five percent (75%) of any excess of "General
9 System" revenues above an annual threshold of $875,287,973
10 ("Excess Revenues").[4]
11 On August 11, 2015, TGP filed its Annual Revenue Sharing
12 Report for the year ending May 31, 2015 ("2015 Revenue Sharing
13 Report"). The 2015 Revenue Sharing Report indicated that General
14 System Revenues received by TGP were $890,534,688, resulting in
15 $15,246,715 of Excess Revenues during the Revenue Sharing
16 Period, of which the Eligible Customer's share was $11,435,036.
17 Distribution received its share of the Excess Revenues of
18 $575,092.92 as a credit on TGP's July 2015 invoice billed in August.

[4] The Revenue Crediting Threshold amount was reduced from $885,000,000 to $875,287,973 effective on September 1, 2013. See *Tennessee Gas Pipeline Company, L.L.C.*, Article VII, Stipulation and Agreement, Docket No. RP12-887-000 and CP12-490-000, (consolidated), dated July 26, 2012; approved by the Commission on May 31, 2013, 143 FERC ¶ 61,196; *Tennessee Gas Pipeline Company, L.L.C.*, Compliance Filing, Docket No. RP13- 1374-000, dated September 30, 2013; approved by the Commission on February 3, 2014, 146 FERC ¶ 61,062.

1 $328,970.08 of the refund was associated with capacity held for New
2 York.
3 TGP was obligated to file a final Revenue Sharing Report for
4 the period of June 1, 2015 through October 31, 2015. Per TGP,
5 General System Revenues received by TGP during this period were
6 $364,371,400, resulting in $6,306,845 of Excess Revenues. The
7 Eligible Customer's share of such Excess Revenues is $4,730,133.
8 Distribution received its share of the Excess Revenues of
9 $266,846.49 as a credit on TGP's December 2015 invoice billed in
10 January 2016. $154,741.74 of the refund was associated with
11 capacity held for New York.
12 Comeback Provision: Article XVI(E) of the 2011 Settlement
13 required TGP to file a general rate case no later than May 31, 2015
14 (to be effective no later than November 1, 2015). TGP entered into
15 confidential settlement discussions with its customers in an effort to
16 obviate the need for a rate case proceeding. Settlement negotiations
17 progressed during the historical period as discussed below.

18 **Tennessee Gas Pipeline Company, L.L.C.**
19 **Settlement in Lieu of Rate Case - Docket No. RP15-990**

20 On December 2, 2014, Distribution attended TGP's initial
21 settlement meeting in Newark, New Jersey. Following that meeting,
22 TGP began responding to information requests from the active
23 parties and set up a website to allow them access to TGP's
24 responses and certain other data. Distribution participated in

1 settlement negotiations as a member of the Northeast Customer
2 Group[5] which retained cost of service and cost allocation experts to
3 analyze the data provided by TGP. The Northeast Customer Group
4 met regularly via conference call to discuss the experts' findings and
5 participated in numerous conference calls with other active parties
6 and TGP. Distribution attended a second settlement meeting with
7 TGP on February 13, 2015, in Newark, New Jersey. The active
8 parties subsequently exchanged several settlement proposals and
9 counter-proposals, reaching a settlement in principle in April 2015.
10 On May 15, 2015, TGP filed the final settlement at the FERC under
11 Docket No. RP15-990 ("2015 Settlement"). The FERC issued a letter
12 order approving the 2015 Settlement on July 1, 2015.
13 The 2015 Settlement, among other things, initiated new rates
14 which became effective November 1, 2015, providing an immediate 3
15 percent reduction from TGP's then effective rates. It also provides for
16 subsequent rate reductions of an additional 2 percent as of
17 November 1, 2018, and if certain conditions are met, two additional

[5] The Northeast Customer Group includes the following entities: The Brooklyn Union Gas Company d/b/a National Grid NY; KeySpan Gas East Corporation d/b/a National Grid; Boston Gas Company and Colonial Gas Company, collectively d/b/a National Grid; Niagara Mohawk Power Corporation d/b/a National Grid; and The Narragansett Electric Company d/b/a National Grid, all subsidiaries of National Grid USA, Inc (collectively the "National Grid Gas Delivery Companies"); National Fuel Gas Distribution Corporation; Bay State Gas Company d/b/a Columbia Gas of Massachusetts, The Berkshire Gas Company, Connecticut Natural Gas Corporation, Fitchburg Gas and Electric Company, City of Holyoke, Massachusetts Gas and Electric Department, Northern Utilities, Inc., NSTAR Gas Company, The Southern Connecticut Gas Company, Westfield Gas & Electric Department and Yankee Gas Services Company ("the New England LDCs"); New Jersey Natural Gas Company;

1 rate reductions of 1 percent on November 1, 2020 and November 1,
2 2022 (collectively, "Rate Reductions").[6] The 2015 Settlement also
3 obligates TGP to file cost-revenue studies, at dates certain in the
4 future, to provide shippers and the FERC with an opportunity to
5 evaluate TGP's rates if an NGA Section 4 or Section 5 proceeding
6 has not already been initiated.

7 **Transcontinental Gas Pipe Line Company, LLC**
8 **RP12-993 Stipulation and Agreement**

9 On February 11, 2015 Distribution attended a meeting of
10 interested parties to discuss pooling structure on the Transco system.
11 Transco was required to convene the meeting pursuant to a
12 Stipulation and Agreement ("Agreement") filed in the Docket No.
13 RP12-993 rate case proceeding. Meeting attendees proposed that
14 Transco create a Leidy Line pool to facilitate transacting and pricing
15 of gas produced along the Leidy Line. In addition, to promote the use
16 and liquidity of market area pools it was suggested that Transco
17 charge its transportation fees when gas is moved from a market area
18 pool as opposed to the current practice of charging the fees when gas
19 is moved to the pool.

20 Although Transco actively participated in the discussions and
21 agreed to consider the suggestions for future implementation, under

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and PSEG Energy Resources & Trade LLC.

[6] These rate reduction obligations arise provided that an NGA Section 5 rate proceeding has not been initiated against TGP and TGP has not filed an NGA Section 4 general rate case prior to either November 1, 2020 or November 1, 2022.

1 the terms of the Agreement they are not obligated to support or file
2 proposals resulting from the meeting.

3 **Canadian Regulatory Issues**
4
5 **TransCanada's Energy East Project**
6
7 The Energy East Pipeline Project ("Project") is a $10 Billion,
8 2,740 mile oil pipeline proposal that will carry 1.1 million barrels of
9 crude oil per day from Alberta and Saskatchewan to refineries in
10 eastern Canada. The Project requires that approximately 1,800 miles
11 of existing natural gas pipeline be converted to oil. The Project's
12 30,000 page application was submitted to the NEB on October 30,
13 2014, the Project was amended in December 2015 and has not yet
14 been accepted as "complete" by the NEB.
15 Distribution has been working through the TTF and ANE
16 customer group to protect its interests with respect to the Project. On
17 February 13, 2015 ANE applied to be an intervener in the
18 proceeding.

19 **TransCanada's RH-001-2014 Compliance Filing**

20 Early in 2013 TransCanada and the three major eastern Ontario
21 LDCs filed a contested application with the NEB to expand and
22 reconfigure TransCanada's pipeline system to accommodate growing
23 levels of Marcellus supply. If approved the application would
24 increase tolls by more than 50% through 2020. A hearing was
25 conducted, and despite fierce opposition from ANE, a decision

approving the application was issued by the NEB in December 2014. Responding to TransCanada's March 31, 2015 compliance filing, ANE submitted a request to the NEB for a formal Process Review. ANE indicated that in deriving the tolls TransCanada underestimated future revenues and did not properly adhere to NEB guidelines. Although the NEB rejected ANE's request, TransCanada was required to provide stakeholders with an opportunity to submit comments regarding the compliance filing. ANE submitted additional comments expanding on its concerns and providing detailed analysis of the issues addressed in its April 7, 2015 request for a Process Review.

Despite ANE's efforts, the NEB rejected ANE's arguments and the compliance filing became effective July 1, 2015.

Gas-Electric Communications of Operational Information: Communication of Operational Information Between Natural Gas Pipelines and Electric – Docket No. RM13-17; Tariff Revisions: PJM Interconnection, L.L.C. ("PJM") – Docket No. ER14-1469; and Tariff Revisions: New York Independent System Operator, Inc. ("NYISO") Docket No. ER14-2895

On November 15, 2013, the FERC issued Order 787 amending its regulations to provide explicit authority to interstate natural gas pipelines and public utilities that own, operate, or control facilities used for the transmission of electric energy in interstate commerce to share non-public, operational information with each other for the purpose of promoting reliable service or operational planning on either the public utility's or pipeline's system. On June 19, 2014, the

1 FERC issued an Order on Rehearing ("Order 787-A"). Collectively
2 Order 787, *et.al.* recognize the important role LDCs play in the
3 delivery of natural gas to electric generators. FERC allowed for
4 electric transmission operators to share non-public, operational
5 information with LDCs, subject to various conditions, if provided for in
6 tariff provisions approved by the FERC. In response, both PJM and
7 NYISO filed tariff revisions designed to permit such communications
8 between themselves and interstate natural gas pipelines and LDCs.
9 While Distribution supports FERC's objectives in Order 787, *et.al.* it
10 finds some of the PJM and NYISO tariff provisions untenable because
11 they would impose conditions that expose LDCs to various risks:
12 principally FERC tariff violations that could lead to penalties and/or
13 fines. Through filings in the above mentioned FERC dockets made
14 prior to and during the historical period, including comments, protests
15 and rehearing/clarification requests, Distribution sought and received
16 guidance from FERC that will allow Distribution to communicate with
17 PJM and NYISO without bearing undue risk.

18 **FERC Rulemakings and Generic Federal Proceedings**

19 **American Gas Association**

20 Distribution is an active member of the American Gas
21 Association ("AGA"). Through the AGA, Distribution has participated
22 in recommending positions to the FERC, appellate courts and
23 Congress on issues of importance to Distribution and LDCs as a

1 group. Distribution has found that active participation in AGA is an
2 effective and efficient way to ensure that its position is heard on the
3 large generic issues facing LDCs. As a member of AGA, Distribution
4 advocates development of LDC positions consistent with its own
5 stance on such issues. Some of the issues addressed through AGA
6 during the historical period, at times jointly with other industry
7 associations, are: Coordination of the Scheduling Processes of
8 Interstate Natural Gas Pipelines and Public Utilities (FERC Docket
9 No. RM14-2); Cost Recovery Mechanisms for Modernization of
10 Natural Gas Facilities (FERC Docket No. PL15-1); Centralized
11 Capacity Markets in Regional Transmission Organizations and
12 Independent System Operators (FERC Docket No. AD13-7); Winter
13 2013-2014 Operations and Market Performance in RTOs and ISOs
14 (FERC Docket No. AD14-8); and Collection of Connected Entity Data
15 from Regional Transmission Organizations and Independent System
16 Operators (FERC Docket No. RP15-23). Additionally, AGA submitted
17 comments addressing Revised Draft Guidance for Federal
18 Departments and Agencies on Consideration of Greenhouse Gas
19 Emissions and the Effects of Climate Change in NEPA Reviews,
20 Council on Environmental Quality, 79 Fed. Reg. 77802.
21 Of the AGA matters noted above, Distribution had a particular
22 interest in the matters relating to the operational relationship between
23 the gas and electric industries, especially as they related to the start

of the gas day and timeline for gas nominations. Distribution transports gas to electric generators and has an interest in maintaining service reliability as the gas-fired generation load on the regional pipeline grid continues to increase. As price volatility in capacity constrained regions has increased, the FERC has increased its focus on the operational relationship between the gas and electric industries, especially as they relate to the start of the gas day and timeline for gas nominations.

On April 16, 2015, the FERC issued an order in Docket No. RM14-2, Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities ("Order 809"). Order 809 adopted a NAESB proposal to move the Timely Nomination Cycle deadline for scheduling gas transportation from 11:30 a.m. Central Clock Time ("CCT") to 1 p.m. CCT and the proposal to add a third intraday nomination cycle during the gas operating day to help shippers adjust their scheduling to reflect changes in demand. Order 809 did not adopt a proposal to move the 9 a.m. CCT start of the gas day to 4 a.m. CCT. The FERC concluded that, while certain efficiencies could be achieved through a better alignment of the natural gas and electric operating days, a change in the start time for the nationwide natural gas day was not justified.

Although staffing hours may need to be adjusted, Order 809, which is to be implemented by pipelines by April 1, 2016, is not

1 expected to significantly impact Distribution's ability to purchase and
2 schedule gas. Distribution will be enhancing its Transportation
3 Scheduling System to permit marketers serving customers on
4 Distribution's systems to utilize the revised nomination timeline to
5 schedule gas to their customers.
6 Another issue of interest to Distribution was the FERC's
7 Proposed Policy Statement under Docket No. PL15-1 ("Proposed
8 Policy Statement") issued on November 20, 2014 to provide greater
9 certainty concerning the ability of interstate natural gas pipelines to
10 recover the costs of modernizing their facilities and infrastructure to
11 enhance the efficient and safe operation of their systems. The
12 Proposed Policy Statement explains the standards the FERC would
13 require interstate natural gas pipelines to satisfy in order to establish
14 simplified mechanisms, such as trackers or surcharges, to recover
15 costs associated with replacing old and inefficient compressors and
16 leak-prone pipes and performing other infrastructure improvements
17 and upgrades to enhance the efficient and safe operation of their
18 pipelines. Distribution worked with AGA to develop comments, which
19 were filed on January 26, 2015.
20 After review of the comments on the Proposed Policy
21 Statement, the FERC issued a Policy Statement on April 16, 2015
22 ("Policy Statement"), establishing a policy allowing interstate natural
23 gas pipelines to seek to recover certain capital expenditures made to

1 modernize system infrastructure through a surcharge mechanism,
2 subject to conditions intended to ensure that the resulting rates are
3 just and reasonable and protect natural gas consumers from
4 excessive costs. The FERC recognized that permitting pipelines to
5 recover these expenditures through a surcharge or tracker departs
6 from the requirement that interstate natural gas pipelines design their
7 transportation rates based on projected units of service. However,
8 the FERC found that consideration of such mechanisms is justified if
9 they are properly designed to limit a pipeline's recovery of such costs
10 to those shown to modernize the pipeline's system infrastructure in a
11 manner that enhances system safety, reliability and regulatory
12 compliance, and are subject to conditions that ensure that the
13 resulting rates are just and reasonable. Therefore, the FERC
14 adopted the Policy Statement to provide guidance and a framework
15 as to how it will evaluate pipeline proposals for recovery of
16 infrastructure modernization costs. The Policy Statement sets forth
17 five standards a pipeline would have to satisfy for the FERC to
18 approve a proposed modernization cost tracker or surcharge. Those
19 criteria are (1) Review of Existing Base Rates; (2) Defined Eligible
20 Costs; (3) Avoidance of Cost Shifting; (4) Periodic Review of the
21 Surcharge and Base Rates; and (5) Shipper Support.
22 **Commodity Futures Trading Commission**

1 The Dodd-Frank Wall Street Reform and Consumer Protection
2 Act ("Dodd-Frank Act" or "Act") was signed into law by the President
3 on July 21, 2010. A component of the Act calls for sweeping reform
4 of the derivatives market, largely under the auspices of the
5 Commodity Futures Trading Commission ("CFTC"). Distribution,
6 independently and through AGA (as noted below), is monitoring
7 rulemakings issued by the CFTC that may have an impact on
8 Distribution. Based on final rulemakings to date and the fact that
9 Distribution currently does not engage in financial hedging activities,
10 Distribution has not been significantly impacted by the Act's
11 requirements. Distribution's physical hedging activities, including
12 peaking supply contracts with volumetric optionality, appear to be
13 exempt forward contracts that are not subject to the onerous
14 regulatory requirements imposed on "swaps". This exemption is
15 subject to pending clarification of a component of a seven factor test
16 developed by the CFTC in its product definitions rulemaking. If as a
17 result of future clarification by the CFTC it is determined that
18 contracts with volumetric optionality are not exempt from the
19 definition of swap, under the commodity options rulemaking these
20 contracts would be considered "trade options" subject to significantly
21 less stringent recordkeeping and reporting requirements than swaps.
22 In an abundance of caution, Distribution has reported and maintained
23 these contracts as though they were trade options pending final

1 clarification by the CFTC. Distribution will continue to monitor Dodd-
2 Frank Act developments that may affect Distribution. Issues
3 addressed by AGA (at times jointly with other industry associations)
4 relative to matters handled by the CFTC are as follows: Proposed
5 Rule on Margin and Capital Requirements for Covered Swap Entities
6 (RIN Nos. 1557-AD43, 7100-AD74, 3064-AE21, 3052-AC69 and
7 2590-AA45); Margin Requirements for Uncleared Swaps for Swap
8 Dealers and Major Swap Participants (RIN No. 3038-AC97);
9 Proposed Interpretation regarding Forward Contracts with Embedded
10 Volumetric Optionality (RIN No. 3038-AE24); Position Limits for
11 Derivatives (RIN No. 3038-AD99); Proposed Rule, Records of
12 Commodity Interest and Related Cash or Forward Transactions, 79
13 Fed. Reg. 68140; Request for No-Action Relief Regarding the CFTC
14 Trade Option Reporting Requirements, 17 C.F.R. § 32.3(b)(1)-(2);
15 and Proposed Rule, Trade Options (RIN No. 3038-AE-26).

16 **Gas-Electric Coordination**

17 Over the past few years FERC has placed considerable priority
18 on the discussion of Gas-Electric Coordination matters. Several
19 Technical Conferences have been conducted by FERC involving
20 interest from both gas and electric markets and orders addressing
21 Gas-Electric Coordination matters have been issued. In addition to
22 gas day/nomination issues, FERC has been exploring the impacts of
23 natural gas supplies and capacity as they relate to market price

formation within organized electric markets. Distribution transports gas to electric generators and has an interest in maintaining service reliability as well as how nomination protocols may change in response to increased gas-fired generation load on the regional pipeline grid.

In addition to participating through AGA on these matters, Distribution filed interventions in the following PJM proceedings: Revisions to the OATT and RAA re Capacity Performance (FERC Docket No. EL15-623) and Compliance Filing per 3/20/14 Order in Docket No. EL14-24 and Order 809 (FERC Docket No. EL15-2260). Distribution also participates in PJM Interconnection's Gas Electric Senior Task Force. However, PJM has placed the task force into hiatus for the near term.

North American Energy Standards Board

Distribution is a member of NAESB within the Retail Markets Quadrant, Retail Gas Market Interests Segment. NAESB is a broad-based standards organization, which addresses standards/model business practices development for three industry quadrants: Wholesale Gas, Wholesale Electric, and Retail (addressing both gas and electric retail business practices). Distribution's participation in NAESB helps to ensure that the LDC position is recognized in resolving the many issues being addressed by this organization. Distribution has closely monitored the ongoing NAESB compliance

filings made by the upstream pipelines, filing substantive comments as warranted.

With respect to the Wholesale Gas Quadrant, the primary focus of NAESB's efforts during the past couple years has almost exclusively been on a FERC Notice of Proposed Rulemaking in FERC Docket RM14-2 which led to changes in industry standard gas nomination deadlines. This quadrant has also addressed the issues of modifications to NAESB agreements as a result of regulatory changes associated with implementation of the Dodd-Frank legislation by the CFTC and design of updated FERC reporting forms pursuant to the Order Instituting Proceeding to Develop Electronic Filing Protocols for Commission Forms (FERC Docket No. AD15-11). Distribution has participated in these discussions at NAESB.

During 2015, the Retail Markets Quadrant focused its efforts on Demand Side Management, Energy Efficiency and net metering, all of which have service implications for retail electric markets. With regards to customer-choice oriented standards (impacting both retail gas and retail electric markets), NAESB focused on maintenance of technical standards and documentation intended to support business practices concerning various transactions including billing, payment processing and exchange of customer information. Distribution participates on the retail level to ensure that model business practices reflect, and are consistent with, existing successful

1 business practices that have evolved from gas transportation
2 programs dating back to the mid-1980s.

3 **D.C. Circuit Proceedings**

4 In addition to its efforts at the FERC, Distribution pursues issues
5 in litigation in other forums where appropriate. Generally, this
6 includes filing petitions for review of FERC orders and/or intervening
7 in cases brought before the United States Court of Appeals for the
8 District of Columbia Circuit ("D.C. Circuit"). Currently, there are no
9 pending D.C. Circuit actions filed by Distribution.

10 **Affiliate Rule Compliance & Miscellaneous Agreements**

11 Q. Please describe the means by which the department properly
12 observes the affiliate rules?

13 A. Employees in the Gas Supply Administration Department undergo
14 annual training by Distribution's in-house counsel that includes a
15 review of the State Marketing Affiliate Rules. These employees could
16 be in circumstances that require heightened attention to prevent and
17 avoid affiliate preference. These employees receive training with
18 respect to the affiliate rules and are required to sign a statement
19 indicating that they understand and will observe the rules. These
20 employees are also instructed to contact Company counsel when
21 they have questions or are in doubt about the applicability of a rule.

1 Q. Provide all documentation (i.e., contracts, delegation of authority,
2 etc.) pertaining to gas supply arrangements that exist or have existed
3 with any affiliated marketing/trading organizations.
4 A. From time to time, the Company may make automatic, non-
5 discretionary purchases and/or sales of monthly imbalance gas to
6 and from energy service companies ("ESCOs"), which includes
7 National Fuel Resources, Inc. ("NFR"), its affiliate, relative to the state
8 approved ESCO program. These transactions with ESCOs, including
9 NFR, are performed in the ordinary course of business under the
10 Company's tariff and in a non-discriminatory manner.
11 Q. Has the Company entered into power purchase agreements
12 ("PPAs")?
13 A. The Company has no such agreements.
14 Q. Does the Company communicate with the NY PSC on a regular basis
15 with respect to its gas supply administration activities?
16 A. Prior to each winter season, the Staff of the Department of Public
17 Service ("DPS") conducts its annual review of each gas utility's gas
18 supply portfolio. The review focuses on a gas portfolio and
19 purchasing strategy for the upcoming sendout year; portfolio changes
20 over the next five years as capacity contracts expire; plans to
21 diversify purchases to limit price volatility; natural gas and electric
22 market convergence; and bill impacts.

The review is submitted in writing to the DPS, which is then followed by an onsite meeting to discuss the annual review and the winter outlook. Requests for additional supporting documentation regarding issues and concerns discussed at the meeting are submitted to the DPS Staff as requested.

During the winter period, the DPS requires reporting of storage inventories at the midpoint and end of each month.

Q. Does this conclude the panel's testimony?

A. Yes, it does at this time.

Q. Please state the members of this Gas Supply Administration Panel ("Panel").

A. We are Christopher A. Cej, Kenneth B. McAvoy and Robert M. Michalski.

Q. Mr. Cej, please state your business address.

A. My business address is 6363 Main Street, Williamsville, New York, 14221.

Q. By whom are you employed and in what capacity?

A. I am employed by National Fuel Gas Distribution Corporation ("Distribution" or "Company") as Assistant General Manager within the Gas Supply Administration ("GSA") Department.

Q. Mr. McAvoy, please state your business address.

A. My business address is 6363 Main Street, Williamsville, New York, 14221.

Q. By whom are you employed and in what capacity?

A. I am employed by Distribution as Assistant General Manager within the GSA Department.

Q. Mr. Michalski, please state your business address.

A. My business address is 6363 Main Street, Williamsville, New York, 14221.

Q. By whom are you employed and in what capacity?

A. I am employed by Distribution as Assistant General Manager within the GSA Department.

Q. Has the Panel testified previously in this case?

A. Yes, we provided Direct Testimony and Exhibits regarding Distribution's gas purchasing practices, as required by Public Service Law §66-e (2) and Part 61.3 (d)(6) of the Commission's rules and regulations as well as how the

GSA Department complies with the rules that govern transactions between Distribution and its marketing affiliate.

Q. What is the purpose of your Rebuttal Testimony?

A. The purpose of the Panel's rebuttal testimony is to respond to the testimonies of Staff Gas Policy and Supply Panel ("Staff") and EnergyMark, LLC ("EnergyMark"). The Panel's rebuttal testimony will address Staff's testimony first; and EnergyMark's testimony second.

Q. What portion of Staff's testimony does the Panel wish to respond to?

A. This Panel will address the Local Production Issues presented in Staff's testimony. The Company remains steadfast in its proposal to waive all monthly meter charges imposed on local producers for the continued operation and maintenance of those interconnection facilities producing a minimum of 1 MCF/day.

Q. What does Staff propose and does the Panel agree with such proposal?

A. Staff proposes that the Company continue to maintain all meter interconnection points, even those that receive less than 1 MCF/day. The Panel does not accept Staff's position and disagrees with Staff's assertion that the proposed minimum delivery requirement would eliminate local production access of low flow wells from the distribution system. The Company believes this requirement will not result in large scale well abandonments but will lead to a more efficient and safe operation of the local production infrastructure though the consolidation of low volume production wells behind the Company's existing or new interconnection

facilities. The consolidation will enhance operating conditions through improved gas quality and gas treatment economics. Additionally, proper odorization is more readily achieved at higher delivery volumes.

Q. Are there other reasons why the 1 MCF/day delivery minimum is appropriate?

A. Yes. While the Company may have a certain level of obligation under Public Service Law §§66-d and f to either provide transportation on the Company's system or purchase a producer's indigenous gas, the Company has been advised by counsel that there are caveats to that obligation. For example, the producer's gas must meet certain gas quality standards. To the extent that it fails to meet those criteria, the Company is not obligated to purchase or transport such gas. Moreover, Public Service Law §66-f(2) offers the condition that "no gas corporation shall be required to purchase [indigenous] natural gas where it can demonstrate such purchase would have an adverse impact upon its ratepayers, which cannot be reasonably mitigated." Clearly the Company's obligations in this regard are not without limitations.

Q. Does the Company's believe that maintaining low volume interconnection points have an adverse impact upon the ratepayer?

A. Yes. The cost to maintain existing local production interconnection facilities where the producer's volumes have continually declined over the years to nearly zero in some instances is now a burden with adverse impact on the ratepayers.

Q. How does the Company propose to mitigate this adverse impact on its ratepayers?

A. The Company believes its original proposal fairly mitigates the adverse impact while maintaining efficient and safe access to the Company's system. The Company will waive the monthly meter charge to all local producers who continue to deliver a minimum of 1 MCF/day through the interconnections. Effectively, the cost to local producers will be reduced to the extent the producer delivers a reasonable quantity of indigenous gas to the system.

Q. Does the Company have other concerns regarding Staff's Local Production issue?

A. Yes, the Company is concerned with Staff's proposal that suggests and promotes the Company's involvement with odorization of the producer's facilities upstream of their interconnection with the Company's facilities and the collecting and accounting of deferred funds for purposes of facilitating the installation of odorization equipment on such producer owned upstream facilities.

Q. Please explain further.

A. On page 27, line 22, Staff states, "We recommend that all lines connected to the distribution system be in compliance with the rules and regulations regarding odorization." Further in the testimony, Staff opines that the Company can accomplish this by not waiving the meter charge if the gathering system or individual line from the well does not meet this

requirement and that those meter charges collected by the Company be used to make those facilities compliant.

Q. What is your concern regarding this proposal?

A. First, the Company agrees that local producers should operate their gathering facilities that extend from the local producer's wellhead to the interconnection point with the Company's facilities, in a safe manner. In fact, the Company ensures that its gathering and distribution systems, downstream of the interconnection with local production, are properly odorized. Similar to ensuring other gas quality parameters, such as moisture content, the Company believes local producers bear the responsibility to properly odorize their gas in accordance with Part 255 of the Code. The Company, however, does not own the upstream production facilities and gathering lines, and does not necessarily know the location of the producer's wells, nor does the Company have the landowner's or the producer's authorization to enter their property to inspect such facilities; therefore it is wholly inappropriate to suggest that odorization of gas within a producer's facilities is, in any way, a responsibility of the Company. The Company is simply not responsible for third-party facilities upstream of the Company interconnection as the Company does not own or operate or exercise any control over those facilities.

Q. Does the Company accept Staff's recommendation that it file a survey of the gathering lines for all 971 meter connections?

A. No, the Company does not find Staff's recommendation warranted. Such a survey would include, among other items, the status or verification of each producer's compliance with the rules and regulations regarding odorization of gas. Such compliance could potentially apply to the producer's entire gathering system leading back to multiple wells and not just at the interconnect point. The Company has no legal right to enter landowner's property to perform such verification. Such verification of producers' facilities is properly the domain of the New York Department of Public Service. For these reasons and the reasons stated above, the Company disagrees with Staff's recommendation.

Q. Does that conclude your rebuttal to the testimony prepared by Staff Gas Policy & Supply Panel?

A. Yes, at this time.

Q. Does the Panel wish to provide rebuttal to EnergyMark's testimony?

A. Yes, the Panel would like to respond to the three main issues discussed in EnergyMark's testimony?

Q. What is the first issue presented by EnergyMark that the Panel would like to discuss?

A. EnergyMark claims the credits associated with offsystem sales and capacity release credits provide the Company's Sales Service customers a price advantage over marketers' customers.

Q. Does the Company agree with that statement?

A. No. The credits offset the costs associated with the Company's responsibility to balance daily system deliveries. Marketers, such as EnergyMark, are not required to deliver their gas to the Company citygate stations that physically serve their customers. From the marketer's perspective, the Company operates its system as one contiguous system rather than a zonal system. The marketer may deliver their daily delivery quantities to any Company delivery point during normal operating conditions. However, such deliveries place the system out of balance with portions of the system receiving too much gas and other parts receiving too little gas relative to each region's market requirements. Each day, the Company forecasts system requirements along with marketer delivery trends to determine where these imbalances exist. The Company utilizes its sales customers' pipeline and storage assets to balance deliveries across the entire system each day. As one would expect, marketer delivery trends strongly correlate to market prices; low price regions receive too much gas and high price regions receive too little gas. The recent trend is that marketers are delivering their customers' gas supplies to southernmost low cost citygate receipt points, such as Rose Lake or Leidy but not delivering gas supplies to northernmost higher priced citygate points, such as Niagara. As a result of these trends, the Company has to address the resulting imbalances by utilizing assets reserved for its sales customers to deliver adequate supplies to the expensive portions of the system. This has the effect of inflating the Sales Customers' weighted average commodity and

capacity costs. Under the circumstances, it is entirely equitable that sales customers receive any compensating benefits. Furthermore, EnergyMark commented elsewhere in its testimony that the marketer's residential and non-residential customer throughput has grown to approximately half of the total throughput on the system. These significant volumes delivered by marketers have resulted in a greater balancing obligation borne by the sales customers and may warrant procedural changes that fairly shift some balancing obligations to marketers. To conclude on this point, the Company believes the credit is fair and just compensation to the sales customers for providing system balancing service to the marketer's customers.

Q. What is the second issue presented by EnergyMark that the Panel would like to discuss?

A. The Panel would like to respond to EnergyMark's comments related to the Company's mandatory upstream transportation capacity ("MUTC") associated with the Company's Transportation Program. EnergyMark claims the MUTC longhaul capacity allocated to marketers is not competitive with market area receipt point pricing.

Q. What is the Panel's response to their assessment of the capacity allocation?

A. EnergyMark's assessment is inaccurate. Currently, 100% of the capacity allocated to MUTC marketers provides access to abundant, low cost supplies of market area shale production including Marcellus Shale production at liquid trading points. The Company allocates to those marketers a Tennessee Gas Pipeline ("TGP") firm capacity path through the

market area shale producing regions of Ohio and Pennsylvania with firm delivery rights at the TGP/NFG Supply Rose Lake interconnection. This firm capacity path provides direct access to the TGP Zone 4 200 line and TGP Zone 4 313 pools. The combined daily trading activities at those two pools averages approximately 0.8 bcf and over 150 trades per day. Recent monthly and daily index prices at these points suggest some of the lowest priced gas in the country is trading at these pools.

Q. Do all marketers participating in the Company's transportation program receive MUTC?

A. Most marketers receive monthly MUTC assignment. Some marketers continue to demonstrate their own capacity also known as Grandfathered Upstream Transportation Capacity ("GUTC") instead of requesting MUTC capacity assignment from the Company.

Q. Are there any provisions in the program that prevents marketers from electing and receiving MUTC capacity from the Company?

A. No. The Company's program provides marketers with the flexibility to replace their GUTC capacity with the Company allocation of MUTC capacity.

Q. Does the Panel wish to respond to EnergyMark's comment regarding the acquisition of the Empire capacity?

A. The Company has acquired Empire capacity to aid in serving customers and filling storage, located on the north side of the system. The Company reserves pipeline and storage capacity on several pipelines, along with the responsibility to serve those specific system daily delivery requirements.

Limiting the MUTC allocation to TGP capacity at the overall Weighted Average Cost of Capacity ("WACOC") rate alleviates marketers from managing small allocations of capacity from each pipeline and storage and the burden of meeting regional daily delivery quantities required to balance the system.

Q. Would the WACOC release rate paid by marketers decrease if the Company allocated only the short-haul TGP zone 4 path instead of TGP long-haul paths?

A. No. The WACOC release rate is determined by the Company's entire capacity portfolio and not the MUTC allocation of long-haul and short-haul capacity. Long-haul pipeline capacity paths provide marketers with a capacity release revenue opportunity to offset a portion of their customer's WACOC expense. Marketers are able to release the unused segments, such as the Zone 0 to Zone 4 segment, of the TGP MUTC capacity to the secondary capacity markets.

Q. What is the third issue presented by EnergyMark that the Panel would like to discuss?

A. The panel would like to address EnergyMark's assertion that ratepayers would benefit if the Company offered volumetric capacity releases.

Q. How does the Company generate value for its ratepayers through asset optimization?

A. As explained in the GSA panel testimony, the Company generates significant ratepayer value through its participation in the seasonal, monthly

and daily capacity release markets. The Company is very diligent when participating in the highly regulated capacity release market and follows specific capacity bidding procedures for all releases. For seasonal and monthly releases, the Company solicits bids from parties for specified segmented and non-segmented capacity paths by issuing Request For Proposals to market participants for the selection as a prearranged bidder on the Company's capacity. The Company posts all such capacity on the appropriate pipeline electronic bulletin board ("EBB") open for bidding by all interested bidders. For shorter term releases, including single day releases, to interested parties the Company also posts those releases prearranged and biddable on the pipeline's EBB. The Company will agree to release capacity to a party for the next day if there is adequate time for the Company to post the capacity offer on the pipeline EBB for the prearranged bidder, and allow for a bidding period for all interested parties. The capacity is ultimately awarded to the highest bidder.

Q. Are all of the Company's seasonal, monthly and daily releases structured as demand rate releases?

A. Yes.

Q. How does a volumetric rate release differ from a demand rate release?

A. Demand rate releases require the buyer to pay an agreed upon rate for the capacity regardless of whether the capacity is used. With a volumetric release the buyer obtains the capacity but is only required to pay the seller when the capacity is used.

Q. Wouldn't a volumetric rate release provide the Company with an opportunity to generate incremental revenue when capacity might otherwise remain idle?

A. No, it is more likely that offering volumetric rate releases would reduce revenues by cannibalizing the Company's current demand rate releases. The Company generates significant value in the seasonal, monthly and daily release markets, given the option, existing release customers would likely opt for volumetric agreements, paying for the capacity only when and if the capacity is needed. The Company would lose the premium currently being paid by its current customers for surety of supply. Also, buyers of volumetric rate capacity will only use, or re-release, the capacity when it is worth more than the volumetric release rate. On those days, the buyer would be effectively paying the Company less than market value. If necessary, capacity can be obtained at market rates in the daily release market.

Q. Are there other issues presented by EnergyMark in this proceeding that the Company wishes to address?

A. Yes, the Company would like to address EnergyMark's response to an interrogatory statement from Department of Public Service staff member Mr. Riebel to EnergyMark.

Q. What was the interrogatory statement posed by Mr. Riebel to EnergyMark?

A. Mr. Riebel sought proof or evidence from EnergyMark to support their suggestion that the Company exercises market power over gas transactions in the region.

Q. What is the Company's opinion of EnergyMark's response to Mr. Riebel's interrogatory statement?

A. EnergyMark's response, as shown in Exhibit___(GSA-14), fails to demonstrate evidence or proof for such an allegation. The Company's responsibility to its customers is to provide highly reliable service at the best cost. The acquisition of upstream capacity through open seasons, the purchase of supplies at market prices and the optimization of unutilized capacity are consistent with those responsibilities. Additionally, these actions are in compliance with the Company's tariff and Gas Transportation Operating Procedures, as approved by the Public Service Commission.

Q. Does that conclude your rebuttal to the testimony prepared by Staff Gas Policy & Supply Panel and EnergyMark?

A. Yes, at this time.

BY MR. NICKSON: (Cont'g.)

Q. Panel, do you also have a document entitled The Rebuttal Testimony of the Gas Supply Administration Panel, consisting of thirteen pages of questions and answers?

A. Yes.

Q. And was that document prepared by you or under your supervision?

A. Yes.

Q. Do you have any changes or corrections to the testimony?

A. No.

Q. And if I were to ask you the same questions today, would your answers be the same?

A. Yes.

MR. NICKSON: Your Honor, I would ask that the rebuttal testimony of the Gas Supply Administration Panel be incorporated into the record, as if given orally today.

A.L.J. LECAKES: Granted.

And that is also on the Company's disk under the folder Company Rebuttal Testimony, Gas Supply Administration Panel Rebuttal.

Insert testimony of Gas Supply

BY MR. NICKSON: (Cont'g.)

Q. And Panel, are you also sponsoring thirteen exhibits to your direct testimony, which were identified as GSA One through GSA Thirteen, as well as one exhibit to your rebuttal testimony entitled GSA Fourteen?

A. Yes.

Q. And were those documents prepared by you or under your supervision?

A. Yes.

Q. Do you have any corrections to the -- those documents?

A. No.

MR. NICKSON: Your Honor, I -- I ask that the exhibits that were identified as GSA One through GSA Fourteen, be marked for identification.

A.L.J. LECAKES: Yes.

So we'll mark GSA One as Exhibit 267, GSA Two as 268, GSA Three as 269, GSA Four as 270, GSA Five as 271, GSA Six as 272, GSA Seven as 273, GSA Eight as 274, GSA Nine as 275, GSA Ten as 276, GSA Eleven as 277, GSA Twelve as 278, GSA Thirteen as 279, and GSA Fourteen as 280.

MR. NICKSON: Your Honor, the Panel is

available for cross-examination.

A.L.J. LECAKES: Thank you.

I have listed first for this Panel -- did you withdraw your --

MR. FAVREAU: No.

A.L.J. LECAKES: -- cross on this?

MR. FAVREAU: Yes, I did. There's no cross, your Honor.

A.L.J. LECAKES: Okay. Then I guess Energy Mark is the only party that has cross indicated.

Mr. Marchion?

CROSS EXAMINATION

BY MR. MARCHION:

Q. Panel, good afternoon.

Energy Mark supplies primarily noncore customer behind the National Grid -- as a point of fact, more than two thirds of the transportation revenue go to noncore customers and that's those receiving tax annuities volume, so the smaller volume mass marketing customers, which includes residential. So some of my -- I have three points primarily pertinent and the first being that a capacity releasing off system sales revenues, as it impacts your sales service customers and general rate

payer, which includes transportation customers.

In -- in our interrogatory responses one through six, I will reference those, the panel replied and identified revenues from capacity releasing off-system sales and they range over the last three years between ten and 20 million dollars. When asked directly and we can confirm, this benefit of off-system sales and capacity release is credited to sales service customers as part of the gas supply, is that correct?

A. (Cej) That's correct.

Q. And these off-system sales revenues, which can impact the clients, especially the -- the -- the sales customers, the range of benefit is 30 to 60 cents as identified in your interrogatory response, is that correct?

A. That sounds accurate.

Q. And if these revenues were shared, would you agree that the benefit to the general rate payer, which by fact, pays you a rate of return equally, those service classes, transportation classes and sales services customers, the benefit if a -- if this was spread to those -- over the entire rate base would be subject to even 30 cents per MCF over that time period?

A. It sounds correct.

Q. Okay. And in a two to three dollar gas-price environment, that's a major impact on supply and prices and, you know, it's ten to 15% of the total price based on two to three dollars of natural gas.

In your rebuttal testimony, the NFGD. suggests that there's a subsidy that's occurring because of what's received from energy suppliers in your system and that in fact the residential or core customers are subsidizing the -- the transportation ratepayers and therefore the single retrieval of the -- of the credits -- capacity rates credits back to sales service -- only sales service, is the rationale. Do you still support that?

A. Yeah. I don't -- I don't know if it's a subsidy. It's more of a -- it's an offset to the cost that the sales customers incur for balancing the system. One of the features of our marketing program is that -- as we talked about earlier, one of the requirements is that those customers -- those markets have to deliver a certain set EEQ and they can deliver it to anywhere into the company's system. It's not limited to a specific city gate that's geographically located near that particular customer. You can bring it to any NFGD. in New York and then -- but the customer is then basically -- the -- the company then is able to deliver the gas to that customer

and we rely on -- that creates quite a significant imbalance on our system and as you would expect marketers typically are over delivering to the low-cost parts of the system and then the higher-cost parts of the system are short gas.

So what ends up happening is the sales customers now need the company on behalf of -- we have to use the sales customer's assets now, to go make up that shortfall, go buy gas, utilize the capacity to -- to bring the -- the -- the -- the system back into balance and that ends up costing the sales customers money. So this -- this credit that we're talking about seem -- is a -- is a fair and just offset to that of compensation.

Q. Has there been a cost study done by the distribution company to quantify that impact?

A. No. I'm not -- I'm not aware of any. I maybe defer to the -- the Rates Panel for that.

Q. On the other side, there's a 20 million-dollar credit I'm told so, you know, it's a substantial -- that's a substantial credit is at hand, that could be shared by all ratepayers and instead it's applied just to sales service, with an unknown impact on the south to north.

One more question.

A. Well, on --.

Q. And -- and that's --

A. Let me -- let me --

Q. -- south to north. Let me finish.

A. -- give me an opportunity to respond.

A.L.J. LECAKES: Actually --

BY MR. MARCHION: (Cont'g.)

Q. If this --?

A.L.J. LECAKES: -- actually I -- I would like to allow the witness to respond to that. It wasn't really posed as a question, but I do think it -- it brought up enough information and the witness did have a prepared response after there was a natural break so go ahead.

MR. SANO: Thank you.

A. I -- I, you know certainly you've -- you see large price disparities occurring across our system. The south part of the system, which is in the Marcellus area, very-low cost gas, versus the north part of our system, which is primarily up around the Niagara part of our system, very high prices. So in the wintertime those -- that price spread is pretty significant and we're incurring significant cost to balance the system.

So I -- I disagree with your assertion that the -- whatever the dollar is -- the total dollar amount is, is much larger than what the costs are.

BY MR. MARCHION: (Cont'g.)

Q. But it's unknown --

A. So I don't --.

Q. -- by the --

A. Do -- do you guys --

Q. -- company --

A. -- want to --?

Q. -- at this time?

(McAvoy) Well, I -- I guess I would just, you know, to support that, you know, in the winter of '13-14, gas prices in the northern City Gate region were 40 to 60 dollars. We didn't end up paying any of that gas because we had some prearranged supply arrangements, but we were forced to bring gas to Northern Points in expense to the retail customers.

I think it's important to look at this in its entirety and not just looking at those capacity-release credits. There's advantages and disadvantages built into the program and right now the transporters actually get quite a bit of benefit. We've basically provided them the entire access to all of our acclamation

zones to capacity coming from supply company local production area. They're allowed to use local production to serve their customers requirements that does not involve any upstream capacity.

There's a lot of avoided costs that are built into that and those are just a few examples. You have to look at both sides in its entirety, not just look at one specific item.

Q. You mentioned other capacity and would you agree that it's all subject to available base -- the delivery rather than solid deliveries, north -- north of -- southeast of the delivery area, correct?

A. (Cej) Well, I mean we -- we hold --

Q. It's not automatic delivery. It's if there's space available. Correct?

A. -- well, we hold the firm capacity to make those deliveries, or we have the firm contracts in place to make -- make the deliveries to the system.

Q. Have you released the northern points?

A. (McAvoy) I -- let's just clarify.

(Cej) I mean, the listed --.

(McAvoy) Exactly what are you --?

(Cej) Well, yeah.

(McAvoy) Well, with respect to what?

Q. Have you made releases of northern points?

A. To whom?

Q. To marketers and that includes northern points of Dominion at Porterville, Empire -- Empire releases, permanent releases, or -- or Niagara --

A. When you --

Q. -- for that matter.

A. -- when you say in northern points, I think of Niagara, Pendleton, Tennessee Zone Five and yes we --.

Q. Why isn't Dominion considered northern?

A. Well, consider Dominion and yes we have released that to marketers.

(Cej) Yes.

Q. A single release, am I correct? That's a GUTC --

A. I believe it's --

Q. -- release --

A. -- two.

Q. -- grandfathered --

A. In fact I'm sure it's two.

A.L.J. LECAKES: Please don't talk

over the witnesses. When -- when you ask it, let them answer and then you can respond.

A. (Cont'g.) It's -- it's two and -- you know -- that does have access that can get up into the northern delivery points. It serves market areas that are load driven.

And when you refer to these releases, I guess back to my original point, you know, there's two classes of transportation customers on our system. Those that take capacity from the utility and those that have grandfathered status from 2007, when the transportation program was restructured to accommodate or to allow us to release capacity to the transporter -- transporting customers.

I think what you're referring to is the grandfather capacity further, what you're referring -- referring to is they bring their capacity to us and we release corresponding intermediate capacity on our interstate pipeline affiliate to match up to their upstream capacity and that was established originally in 2007, based on those original contracts that they demonstrated to us and that's where their capacity sat.

Now, periodically, usually annually, we entertain requests to try to move those EFT receipt

points to other points whether that's DTI, Rose Lake or elsewhere and to the extent that there's capacity available, we will honor that request.

BY MR. MARCHION: (Cont'g.)

Q. Back to the question of returns from your customers, transportation customers and sales-service customers contribute to the rate of return. And I'm specifically talking about transportation customers and the release by the company and off-system sales. You're not benefiting from that revenue stream?

A. Well, I would say I disagree with that statement.

(Cej) Yeah.

(McAvoy) I think that based on what I had indicated before that there are -- there's a balance there that -- and you know, based on feedback that we received from other ESCOs that participate in our system, which has been pretty much nothing but -- you know -- positive comparisons relative to other LECs in the state. I think that most of our ESCOs and their customers are very satisfied with the program.

Q. You -- you --?

A. (Cej) Yeah. I -- I guess to -- to -- to go further with that, if -- if a marketer elects to

take our capacity, we provide them basically Tennessee capacity in Zone Four, which basically is the zone that gets you back into the heart of the Marcellus area, so you get a firm path back to the liquid pool point primarily three thirteen and two nineteen, which currently is trading at some of the cheapest gas trading in this country. So the marketers that can speak up, the majority of them like the simplicity of that program because they get access to a firm-capacity path back to the cheapest gas in the country.

Q. Your response to EM eight, you lay out your capacity -- your capacity and availability and how much is released on the pipeline, your Dominion releases which would you agree that Dominion offers the lowest spot and continuous-buy pricing at this -- at this point in the market, the natural-gas market?

A. (McAvoy) No. I would disagree with that.

Q. One of the lowest in the US?

A. Right now if you look at spot prices and you look at the winter strip price for the upcoming winter, you're correct in that they're very close if you look at like Millennium, B.T.I., South Point, Rose Lake, you know, the entire 300 line on Tennessee. They're all

very close and trade closely together.

But when you're buying gas for instance at Rose Lake, it's right in the National Fuel Gas supply, which then feeds into our system. If you're buying it at DTI South Point, you have to add on the variable cost of moving the gas from that point into South Point, so it actually ends up landing at a little bit of a premium in both the spot market and in the current district.

THE REPORTER: Sir, is your mic on?

MR. MARCHION: Is that better?

THE REPORTER: A little bit.

Thank you.

MR. MCAVOY: Well, we can hear you just fine.

MR. MARCHION: Yeah.

BY MR. MARCHIO: (Cont'g.)

Q. Okay. Back to your original assertion that the south to north disparity and receipt points from ESCOs are undefined price impact, but equal or greater than the 20 million dollar in credits received only by the sales service customer. Would northern receipts satisfy the assignment -- or the assignment of capacity in the north satisfy your concern?

A. (McAvoy) I have to admit I'm not --

(Cej) Are you --

(McAvoy) -- sure on this.

(Cej) -- are you suggesting -- are you suggesting --

Q. You're --

A. -- that --?

Q. -- saying that the subsidy occurs -- that you're --

MR. DELVECCHIO: Your Honor, that's --

BY MR. MARCHION: (Cont'g.)

Q. -- your rebuttal is that --.

MR. DELVECCHIO: -- a very confusing question. I'd ask that he clarify that.

BY MR. MARCHION: (Cont'g.)

Q. Yeah. Your --

A.L.J. LECAKES: I --

BY MR. MARCHION: (Cont'g.)

Q. -- rebuttal is that --

A.L.J. LECAKES: -- I think he's trying to.

BY MR. MARCHION: (Cont'g.)

Q. -- that the southern receipts are the -- an adequate off set to those credits. I'm saying then

why not offer northern receipts to your ESCOs?

A. That is a possibility, but again the way the program's designed currently it provides -- it's very simplistic and that allows markets to deliver anywhere right now into NFGDC New York, which is just one nomination point and then the company will distribute that gas across the system.

If we start allocating capacity like that to marketers now, what's -- it's going to complicate the program because what will happen is marketers now will be issued multiple DDQs for multiple parts of the system and we believe that the majority of the marketers that are participating in the program on our system would not prefer that.

Do you want to add anything --

(McAvoy) Let me -- let me just --.

(Caj) -- anything further?

Q. That's an opinion.

A. I -- I have -- and again, I'm -- I'm still trying to understand -- excuse me. I didn't catch the question.

When -- are you -- because I think what Chris was responding to is -- are you suggesting for those folks that receive capacity from the utility that we

consider offering other paths than through Rose Lake?

Q. Absolutely.

A. Okay. So --

Q. Yes.

A. -- for those customers that are taking our capacity assignment, then what Chris said is -- is -- is accurate, you know, right now if you look at the quantity of the amount that we release, we can basically take care of everything through the Tennessee capacity. If we have to start parsing that out, it becomes much more complicated.

Is it providing any advantage? We actually did an informal poll last year and we actually threw out the option. I think it was based on suggestion that you folks came up with, which was could we consider offering Empire and the majority of the people indicated that they prefer to keep it on Tennessee.

Q. Okay. I'll refer once again to the benefits that are available to all ratepayers, including transporters by application of that capacity release credits and at the current time would you agree that the effect of that further lowers -- the capacity-release credits and the sales service further lowers the cost to compare on your system?

A. Not always.

I think if you look at that information that was provided to you, you'll see that there's -- there's more than just the capacity-release credits that get into that adjustment charge. There's also the annual reconciliation charge and you can see, I think it's at least for five of the months that were indicated -- not the majority, it's actually the minority, but that those actually balanced out and created a net-zero impact to the price to compare.

So there is a little bit of an offset, but with the way our rate structure works, there's always going to be a forecast in rates and there's going to either be under or over recoveries and the following year, that could either have a positive or negative impact on gas costs. Do the credits -- you know -- help reduce it if it's a charge against them? Yes.

Can it make it difficult? I -- I understand what you're saying, but I have to go back to look at the program in its entirety.

Local production is a tremendous benefit. Local production that produces directly into our company's pipelines that's a tremendous benefit for the ESCOs and they get -- I -- I think we get somewhere around

100 dekatherms of local production that we take advantage of. The rest of that goes to the ESCOs.

AP Zone Two, which is, you know, in Pennsylvania in the production region, you know, all the capacity that we have on supply company -- all of that's being assigned to the ESCOs.

Q. Thank you, Ken.

And I'll -- I'll point out that's just 17 thousand of your 754 thousand in capacity, so it's insignificant.

A.L.J. LECAKES: Well --

BY MR. MARCHION: (Cont'g.)

Q. The --.

A.L.J. LECAKES: -- to be --.

BY MR. MARCHION: (Cont'g.)

Q. And back to the point of --.

A.L.J. LECAKES: Let the --

MR. MARCHION: Oh, absolutely.

A.L.J. LECAKES: -- witness respond to that.

A. (Michalski) You know, you -- you threw out some numbers there. 17 thousand out of 754 thousand but that's really not the comparison.

The -- the Gupsie (phonetic spelling)

customers demonstrate about -- you know -- it says EM eight. Gupsie release is 31 thousand of the EFT that we release and over 17 thousand goes to AP Zone Two.

Appalachian Zone Two is supplied corporation Pennsylvania. We have a lot of local production on that system -- Marcellus production, very low prices. So more than half of the Gupsie release goes right to AP Zone Two, which is very low cost and -- and I'll just kick in on the DTI, another five thousand goes to Dominion at Porterville to a Gupsie program. So a lot of capacity that we give out does go to inexpensive points, very inexpensive. Okay.

BY MR. MARCHION: (Cont'g.)

Q. As a point of fact, 51 hundred of your 117 thousand of DTI capacity is in the hands of ESCOs.

A. Right. Yes.

Q. That's not much.

Back to the sharing of this and the impact on rates, I operated on the system since 2002 and we've been able to show savings to an end-user versus the utility rates monthly. It's becoming increasingly difficult in the post-Marcellus world and the lack of new pipeline capacity on system.

What diversification has distribution

-- and this is leading to another question, but what diversification have you folks brought forward lately to take advantage of the Marcellus production new capacity?

A. (Cej) Well, I think as we explain in our testimony and as opportunities arise, we evaluate new firm-capacity paths on different pipelines and subject to approval by the Commissions, we make capacity changes and you'll note that in our testimony, we've highlighted how we've been able to shorten up our capacity paths from the Gulf of Mexico up to what we consider -- what's called Zone Four. So we've been reconfiguring, realigning our capacity as the opportunities present themselves in a prudent fashion.

Q. Moving on from the capacity release credits and access to new -- new market area assets and that's a good segue, would you agree Chris, there's been a mountain of changes, positive and negative, with the Marcellus -- the northeast becoming a production zone and your company has reacted to that available gas, am I correct?

A. Oh, certainly.

Q. Would you also agree that your capacity release program has not changed during that same period?

A. I would -- related to what -- related capacity release program in what regard?

Q. The structure, in what you're releasing has not changed in relationship to the market-area production changes.

A. Are you -- I guess I'm confused by the question.

Are you speaking our general capacity release programs or the capacity release programs related to marketers such as yourself?

Q. Well, the release of the Tennessee space has been in place for how many years as your -- as your major release to mandatory upstream.

A. Since the inception of the program.

Q. Okay. And meanwhile the northeast has changed dramatically. Have you changed your program in relationship to the new reality of supply in the northeast?

A. Well, again -- again, speaking -- if you're speaking about the Mutsy (phonetic spelling) program, the -- the capacity that marketers can elect to receive from us, yes, it's still all Tennessee for the most part and if you look at the allocations of the paths, you'll see now it's a percentage of short-haul firm path,

Zone Four Marcellus and long haul and it's consistent with the current contracts that we hold and that's been an evolution over the years.

(McAvoy) Yeah. And --

(Cej) It doesn't --.

(McAvoy) -- and I -- I don't -- I'm sorry to interrupt you.

(Cej) That's all right. Go ahead.

(McAvoy) No. I was just going to kind of add that it -- you know -- Tennessee has always been our largest upstream pipeline, you know, over 200 thousand -- close to 200 thousand dekatherms on that pipe and we've had that and it was all long haul at one point as Chris indicated we've been shortening that up.

And most recently if you talked about how we've changed our capacity the shortening up is part of it, the acquisition -- really it was flipping Empire around. We were using it to take Canadian gas in because as you're well aware that was the cheapest gas into the system, not so long ago. Now it's kind of flipped and we were able to pick up -- or -- or it's really a new contract, but it allows us to pull gas up from the southern lower-cost points.

So that is a change and that was, you

know, as -- it -- because it was brought up by you folks last year, we went out and surveyed. It was an informal survey, but we surveyed folks about do they want that and their issue was that there wasn't enough liquid-trading points where you could attach an index to purchase that gas and enough counter credits to transact with, that made them feel comfortable with that. Not all of them, but the majority of them. There were a few such as yourself that said hey, you know, we wouldn't mind playing around over there.

But with respect to our other capacity, that Tennessee capacity goes right up the three hundred line and into our system at Rose Lake. So we've never had ESCOs coming to us saying they want anything else.

That capacity you're referring to over on DTI, that's Legacy capacity. Those people had those contracts back when Niagara was the cheapest point and they were paying a premium to come in at DTI and they've just continued to hold that all along and it's kind of misleading when you say wow you're only releasing five thousand of your total contract quantities.

A big part of that is storage. Over 80 thousand a day is associated with our storage and we

can't really give up the storage. It feeds a demand center and the load is either very high or very low off there and it would be difficult to take gas on any kind of base-load basis there, consistently.

The capacity we released -- the long haul -- you make it sounds as if that's a curse to obtain the long haul. We're trying to reduce it because our company pay -- the ESCOs pay the weighted average cost of capacity so that pulls up that cost. But the bottom line is whether they get four to four short haul or they get long haul from the Gulf, they're paying us the same price. With the long haul to the Gulf though, they get a lot more flexibility. Get thirteen, fourteen, maybe even fourteen, fifteen.

We were buying gas in the Gulf because the prices -- it was so cold, the prices shot up and it was actually the cheapest point. Not often, but that's flexibility of gas value. You can buy at two nineteen pull. That has value. You can segment and release that capacity, not a lot of value, but it has value.

Why wouldn't you want the long haul? We actually go out of our way when we allocate our Tennessee capacity to those ESCOs that receive the upstream capacity. We go out of the way to allocate from

the long haul first just so they have that advantage and we couldn't be accused of hoarding the best capacity for ourselves. You seem to have turned that around.

They have access to the cheapest gas in the northeast, which is some of the cheapest gas in the country. We're not getting complaints from other ESCOs about that.

Q. We share your need for reliable and inexpensive supply. However, there is other opportunities to access less-expensive supply and new ones on your system. Hasn't the Empire system been added and affirmed storage and transportation capacity in the last three years by National Fuel -- new assets?

A. November 1st of --.

(Michalski) Yeah. You know, let me just clarify, Empire -- we've had that capacity for decades. What we've done is we've changed the receipt points from Canada to the Pennsylvania border, so that capacity has always been in our mix. That reversal -- that flip happened November of '14, I guess -- or '15, within the last three years.

And yes we've added storage. We've also decreased our storage. I guess I'd say our portfolio is -- we're -- we're constantly trying to improve it.

But let me just jump in on the Tennessee that we do release. So, 21 thousand a day of that is short-haul capacity. Only 13 is long haul, just so we know that and understand that most of it is indeed short haul Tennessee capacity, but as Ken mentioned and Chris has mentioned, all of it can access gas in the Marcellus, what -- what you would call in-the-path rights.

So that capacity even though it's been -- again, Tennessee has been released for years, but it's such that it provides access to the cheapest gas today.

Q. Okay. Great.

Would you agree, Bob, that that Tennessee path is one of your most-expensive assets?

A. Well, no.

Q. Is -- before?

A. No. I would --

Q. Not before?

A. -- disagree.

When you consider, again, that 21 thousand a day of that path is Zone four to four, which is like five dollars a dekatherm, the long haul is more expensive. That's why we've reduced it.

But as Ken explained, we have all of our capacity in our portfolio and we have a weighted-

average cost and when we release capacity regardless of whether it's long haul or short haul, it's all at the weighted-average cost.

Q. Agreed, but the company is relieved of that long haul cost by assignment, correct?

A. (McAvoy) No. It's -- the cost --.

(Michalski) Well --

(McAvoy) No, we're not relieved.

(Michalski) -- we're not relieved. I mean if -- if the marketer doesn't pay then we are the ultimate -- we have to pay that bill.

(McAvoy) We have the weighted average cost of our capacity. Whether they take a short haul, long haul, expensive, cheap, it doesn't matter, we're getting the same amount of money for it. We're not any more or less relieved.

(Michalski) Yeah.

(Cej) Well -- well, remember the capacity goes with the customer, so if the marketer elects to take the capacity for the customer, it's -- it's the cost of the capacity, that's what the -- so, we're not really relieved of it because the customer went away. So it's -- it's out there.

Q. Understood.

Back to linking -- linking the system for marketers to the Marcellus gas, RGE and NYSEG have received allocations of Empire space and capacity. They immediately re-released.

When are your plans to release the Empire space, linking back to the newly -- newly recognized liquid point, Corning, New York?

A. We're not familiar with those marketer programs, but at this time we have no plans to modify our -- our mandatory upstream capacity program at this time.

(McAvoy) We considered it last year when we did the inform -- that's why we did this informal survey and we just didn't get enough support to justify changing it because we were considering, you know, we've talked about this. We've -- we were considering just kind of giving 50 percent Empire and 50 percent Tennessee Zone Four and -- you know -- we talked about this with the five largest ESCOs in our system and the five largest ESCOs that actually receive capacity from us, which would be affected by this and we just didn't get the support to justify changing it. It would have upset many people.

Q. However, you could make it available if you chose as a capacity offer?

A. Absolutely.

We could make anything -- well, we can make anything on the system available. It's just we're trying to do what's in the best interests of the ESCOs, as well as the utility and basically processing this program and --.

(Michalski) I -- could you just clarify what you just said as a capacity offer in what sense? To customers that have to take capacity or to --?

Q. As an option on your system?

A. That's --.

Q. You -- you stated you've substantially not made any changes in your capacity to release programs, or access to points since pre-Marcellus. I'm asking why not?

A. I think -- I think Ken's explained it, you know, administratively it's more burdensome on the marketers. They have to deal with two pipes --

Q. Brought -- sorry. Go ahead.

A. -- and he's informally asked those that do take capacity and nobody really wanted to give up Tennessee to take Empire.

MR. DELVECCHIO: Your Honor, I would reserve the right -- I believe perhaps the testimony was mischaracterized in some regard as respect to

changes the company made post-Marcellus.

A.L.J. LECAKES: Yeah. The company will have an opportunity to redirect as necessary, too.

BY MR. MARCHION: (Cont'g.)

Q. Well, thanks. So far, This is good.

Back though to your assertion that North System receipts would benefit you, wouldn't the Empire receipts do just that?

A. So again, there's -- there's two like sets of customers on the system. Small volume customers that have to take capacity, large volume industrial customers that do not take capacity.

When we talk about balancing the system, it's for all of the customers, not only those that take capacity from us and we give them Tennessee Zone Four that delivers the supply at Rose Lake and then the accompanying supply and hands-firm transportation capacity from Rose Lake to the NFGDC New York gate. I mean that's one group of customers.

There's also the industrials and commercials. They also get to deliver to the NFGDC gate and what Ken was alluding to is that, you know, given their druthers, they're going to bring their gas in at the

low-cost, southernmost points on the system and we get instructions then from our gas control every day, how much gas we need to bring in at the north end of the system to balance things out because as Ken explained, the industrial/commercial customers are scattered throughout the system. They're not all in the south. They're up in the north as well.

So that's that balancing that we provide, to offset not only the, you know, the mandatory-capacity customers, the small-volume, but also the industrial/commercial.

So to just give out Empire space in lieu of Tennessee Zone Four to just the small-volume customers, probably wouldn't, you know, totally solve the problem.

Q. Fair. I made the statement that two-thirds of the transportation volumes are non-core and --

A. Yes.

Q. -- my company lives in that space. We have to manage capacity in a very tight-capacity market.

You also react to that because a lot of long haul -- excuse me -- capacity through your system has been sold into Canada. So your upstream -- the -- the next upstream company, National Fuel Supply, you know,

with the intermediate capacity provides a lot of the balancing and services that you're describing through storage and the flexibility they have in their network of pipe.

Does that not satisfy a lot of your concerns for supply on those days your ability to use your intermediate pipe and their flexibility with storage and receipt and delivery points, their direct connects to the interstate pipes such as Empire, Tennessee, in that north system?

A. Well, you know, here, Ken -- Ken will probably jump in, but first off you said that capacity through our system has been sold to Canada.

Q. And I was talking about your intermediate pipeline.

A. Yes, I want to --

Q. Yes.

A. -- clarify you're talking about --

Q. Yes.

A. -- our affiliate interstate pipeline, that connects with Canada, not distribution corporation, but -- go ahead.

(McAvoy) No. I was just going to say that, you know, a lot of -- a lot of the delivery

requirements that we have, these requirements that deliver to different load pockets and storages, those are requirements that our affiliate puts upon us and one of those is to fill the northern storages during the summer. So all summer long when other folks are bringing their gas into the south side of the system, we're bringing it in on the north side.

And then there are load pockets that don't have access to storage deliveries. You know, there's very many -- there's many storages that supply company has and they're -- they're located all over the place and they have different delivery capabilities. They very often don't deliver to the markets that need gas.

Now, our intermediate capacity has something that is referred to as an operational protocol, which basically gives supply the right to tell us to deliver that gas wherever they want it. So, when the marketers was coming to the system, every morning we're working with gas dispatch and they're saying okay this is what's been happening. This is where we need the gas and we have to adjust our planning process to accommodate that.

So it -- it -- it sounds like what you're saying is that that should be helping us to help

smooth this out. They're the ones that are actually pushing us to these other points.

Q. Correct.

And there's -- there's a -- a recognition of that balancing that you folks do in a tighter-capacity market that -- that exist and at post-Marcellus here.

Moving on. Capacity release practices again, we have proposed that the -- the company make available more capacity and when I say more capacity availability, a different form of release which is volumetric, which is a common practice in our industry. So far, in -- in direct answers in our interrogatories, the -- the company has acknowledged that they do not offer volumetric-capacity release. Is that correct?

A. (Sano) Correct.

Q. Okay. We have requested a study of available stranded space on your intermediate pipe. That was not provided, correct?

A. Well, define stranded space.

Q. Unreleased and unused capacity during nonpeak periods and I'm defining nonpeak period of less than 50-degree days and I think there's 310 days of that a year.

A. Yeah. Just -- I wanted clarification because I think stranded capacity is a tariff-related term, so in the context that you're referring to it --

Q. Unused.

A. -- any unused capacity we make available to the general secondary release markets on a monthly basis, on a seasonal basis, on a daily basis, even on a week -- weekly basis. So when we have capacity that we're not using for our own needs, the Commission expects us actually to be out there reducing the cost to our ratepayers and we do that through extensive capacity releases.

Q. I recognize you have an extensive capacity release program. It currently lacks a volumetric offer, correct?

A. Currently -- currently, right. We do not --

Q. Okay.

A. -- do not have a --.

Q. Do you offer day releases on the weekends?

A. Intraday weekends?

Q. Yes.

A. No.

Q. Does --

A. We will --.

Q. -- your DDQs change every day on the weekends?

A. No.

Q. Yes, they do.

A. We have -- we provide DD --.

Q. You have -- you have an average and then you --

MR. DELVECCHIO: Your Honor --.

BY MR. MARCHION: (Cont'g.)

Q. -- change them -- you have --.

A.L.J. LECAKES: The -- the -- you've asked a question and the witness responded.

To the extent that you disagree with the response, you're -- you're definitely able to point that out in post-hearing --

MR. MARCHION: Okay.

A.L.J. LECAKES: -- briefs. You don't need to -- to correct or -- or argue with the witnesses here.

A. (Cont'g.) I guess, too, there's occasions when we suspend the weekend DDQ averaging when there's extreme circumstances, but generally we try to

avoid -- again, we -- we want to try to make it easy for the marketers because we understand there's a challenge if DDQs are changing each weekend day. It's difficult to manage that swing.

So to the extent that we can -- that we have the balancing abilities on our system, we're -- we'll -- we -- we generally allow for DDQ averaging across the weekend days.

(McAvoy) I guess I just want to respond to, you know -- the volumetric release issue, you started off by saying it's common in the industry. I take issue with that. I've been doing this for 25 years and I -- I would say maybe 15 years ago, we did a volumetric release. I think it only took one -- one for us to learn our lesson, that we would never do another one of those.

But they're not common and based on some of your questions, we went out and kind of polled the pipelines. I think, you know, I probably shouldn't name the pipelines, but it was less than -- I -- I think miniscule was said, very rarely, you know, not that they can remember, less than a half of a half a percent. So I'm not quite sure where you got your information that they're very common, but we're just not seeing it.

And logically with respect to making a

volumetric release, it's putting our capacity in your hands with no assurance that you'll ever use it. So if we release your capacity for a nickel, we could leave it with you for the entire month and you would never use it, which is exactly what happened 15 years ago when we did one of these releases. I -- I was monitoring the market every day just to see, oh what could I expect to get by the end of the month and end of the month came and I saw that there was plenty of opportunities to make quite a large margin and I figured oh, I'll be lucky to get half of that.

They never used the capacity at all the entire month. They just sat on it. Now why? Because they were a large marketing company and they probably had all kinds of assets and the last -- the -- the last thing on their list was oh could we take advantage of this nickel release.

For us, it doesn't make sense to do that right now. We do actively participate as Chris said in the monthly -- seasonal, monthly, daily release markets. We make it available. Your point's well taken about the weekend. There are flat nomination cycles.

For the most part, we are -- you know -- we're -- we're subject to the same requirements. We

have to nominate gas base load through the weekend, but I don't think that that's reason to justify doing a volumetric release, you know, the only time a marketer would use a volumetric release is when the market value is worth more than what we released it for. Otherwise they'd just come back to us and ask for a daily release at a lower rate. In that five-cent example, if it was worth three cents, you'd come to us and you'd say oh, I need to buy some more capacity, can I get it for three cents and you'd leave the five-cent capacity idle?

You establish, you know, a maximum that you would pay for that asset and you would only use it when it's worth more than the maximum that you've agreed to pay and then you can take advantage of the minimum. You can go down to -- to the minimum rate, but they're, you know, if it's worth -- and now we're starting to see that based on the capacity that you -- you get and the systems that it's feeding, if it's a 60-dollar day, you basically picked up some capacity at a very low cost and you can take advantage of that. It -- it just makes no sense.

And also we do have customers that come to us and pick up capacity on a baseload basis just in case they need it. They do that. They're willing to

pay a premium for surety of supply.

Where would they go if we started offering volumetric releases? They'd all line up for volumetric releases. We'd lose all that business.

Q. As a point of fact, volumetric releases can carry a minimum volume requirement also. You can have a minimum daily on a volumetric release. So an implied minimum, if you released five thousand, you can have an implied minimum of two thousand and guarantee yourself, in essence, a reduced-reservation rate, but a combination of reservation and volumetric.

A. When -- when you start establishing minimums, you may as well just narrow the band down and do a demand charge release and that's what we do.

Q. Uh-huh.

My point about release capacity and volumetric release is to match power generation loads and the varying loads -- heat-sensitive loads of your customers, even during nonpeak periods and there's an essential need for that capacity to provide low-cost service.

Question on -- back to the volumetric release, has there been any calculation -- we've submitted interrogatory 11, requesting a study or a brief study of

the potential incremental revenue, on top of your existing reservation release capacity revenues.

Any further -- has anything further been done on that?

A. No. I think we stand by our testimony.

Q. I'll offer my own.

At 50 thousand --.

MR. DELVECCHIO: Objection, your Honor.

A.L.J. LECAKES: No. This isn't -- sustained.

This is -- this is not the time -- this is not the time to offer testimony. Testimony was -- was established on a schedule. This is the time for questioning of panel.

Seriously please --

MR. MARCHION: I --.

A.L.J. LECAKES: -- please keep it to the question.

BY MR. MARCHION: (Cont'g.)

Q. There could be -- would you agree there is revenue available in incremental capacity, of your stranded space because that's worth -- that's

recovering zero for you, on any level of -- and any use at any percentage level of volumetric release, incremental revenues to the company?

MR. DELVECCHIO: Object, your Honor. That's a very confusing question.

A.L.J. LECAKES: Did the Panel understand the question enough to answer it?

A. I -- I --

BY MR. MARCHION: (Cont'g.)

Q. Releasing it any --

A. -- I would --

Q. -- time would be incremental revenue.

A. -- I would I say we stand by our --

Q. That's my question.

A. -- rebuttal testimony, which basically indicated that our greatest concern would be that it would cannibalize our existing releases and actually result in less payback to our retail customers.

Q. So, zero on -- on stranded -- unused capacity is acceptable --

A. Net -- net impact --

Q. -- when --?

A. -- to our release revenues.

Again, it's -- it's -- it's -- it --

it's -- I can only guess because there is no empirical evidence that you could acquire that would indicate the value because there are no volumetric releases for the most part being done in the industry, so I'm not sure how we would ever determine what that value would be, but I think it's a valid concern to just look at it at face value and say this has the potential to be a real detriment to our release revenues because of its impact on our current demand rate releases.

Q. Is it true you have the ability to limit the volumes you submit for volumetric?

I mean it's -- it's your choice. You can emit -- you can allow some volumetric releases and the rest reservation based.

A. (Sano) I -- we don't think that's appropriate.

You know I think --.

MR. DELVECCHIO: Your -- your Honor, that was asked and answered.

A.L.J. LECAKES: Yeah. I was thinking the same thing.

How is that different in -- I mean, as -- so far I've heard the question asked a few different times about whether the company was willing

to -- to consider volumetric release and -- and it's been a consistent no answer all three times. And I know there was a little bit of a twist on this one, but essentially it all boils down to the same thing, you know, is the company going to change its mind and -- and -- and start a volumetric release program and I don't expect the -- the panel at this point to start changing its answer.

So -- so if you could move on to a different question, a different topic.

Thank you.

MR. MARCHION: Fair enough.

BY MR. MARCHION: (Cont'g.)

Q. We covered capacity release and off-system sales, access to new market-area receipt points. We covered capacity release practices of the company as they exist, which essentially haven't changed in several years. We -- we have asked that -- that gas costs be addressed as it relates to these credits very importantly and -- and as it relates to cost to compare of ESCO services to those of the utility sales service.

So in the long run, with the capacity-release programs you have in place and new capacity entering the system, again I asked what new plans for

capacity release to new points have been proposed by National Fuel --?

MR. DELVECCHIO: Your Honor, he said it himself that he's asking again.

A.L.J. LECAKES: Sustained. Yeah.

It -- are -- are there any new lines of questioning?

MR. MARCHION: Those are my three areas of cross, sir.

A.L.J. LECAKES: Okay. I -- I -- I think we've got enough in the record now for briefing.

Would anyone else like to cross-examine this panel?

Yes, Mr. Mager?

MR. MAGER: I -- yes, sir.

CROSS EXAMINATION

BY MR. MAGER:

Q. I just want to make sure I -- I'm understanding that from what a couple of the questions and answers.

The -- there's been some discussion of capacity release. This is capacity that NFG has on upstream pipelines, that are released when not needed by

the company, correct?

A. (Sano) That's one type of release we talked about, yes.

Q. Okay. And for that capacity, are any of the -- are the costs of any of that capacity currently charged to the large transportation customers?

A. I don't -- that's probably for the Rate Panel, but I don't believe so.

MR. MAGER: Okay. Okay. Thank you.

A.L.J. LECAKES: If the company attorneys would like to approach and -- and discuss redirect.

Let's go off the record.

(Off-the-record discussion)

MR. DELVECCHIO: Your Honor, the Company does not have any redirect for the panel.

A.L.J. LECAKES: Great.

Thank you.

The panel is excused.

Staff, could you please call your next panel or witness?

MS. AISSI: Staff calls its Site Investigation and Remediation Panel.

A.L.J. LECAKES: All right. Panel

members, can you please identify yourself by name and your business address for the record?

MR. FLAUM: Jeremy Flaum, 3 Empire State Plaza, Albany, New York.

MR. CASTANO: John Castano, same address.

MR. SEMEXANT: Claude Semexant, same address.

A.L.J. LECAKES: Panel members, could you please rise and raise your right hands.

Do you swear or affirm that the testimony that you're about to give today is the whole truth?

MR. CASTANO: Yes.

JOHN CASTANA; Sworn

MR. FLAUM: Yes.

JEREMY FLAUM; Sworn

MR. SEMEXANT: Yes.

CLAUDE SEMEXANT; Sworn

A.L.J. LECAKES: Please be seated.

Counsel, proceed.

DIRECT EXAMINATION

BY MS. AISSI:

Q. Members of the Panel, has the Panel's

pre-filed testimony for this case been prepared by you or under your supervision?

A. (Flaum) Yes.

(Castano) Yes.

Q. And is the 23-page document in front of you that testimony?

A. Yes.

Q. Do you wish to make any changes to that testimony?

A. No.

Q. If I were to ask you the same questions today as that are in your prepared testimony, would your answers be the same?

A. Yes.

MS. AISSI: Your Honor, I ask that this testimony be incorporated into the record, as if given orally today.

A.L.J. LECAKES: Granted.

At this point the transcript should have the testimony, the file Staff SIR Panel Testimony inserted into the record.

Insert Testimony of SIR Panel.

BEFORE THE
STATE OF NEW YORK
PUBLIC SERVICE COMMISSION

In the Matter of

National Fuel Gas Distribution Corp.

Case 16-G-0257

August 2016

Prepared Testimony of:

Staff Site Investigation and Remediation Panel

Jeremy Flaum
Utility Analyst 3
Office of Electric, Gas and Water

John Castano
Auditor Trainee 2
Office of Accounting, Audits and Finance

Claude Semexant
Utility Engineer 1
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State of New York
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Q. Please state the names, employer, and business address of the Staff Site Investigation and Remediation (SIR) Panel.

A. Our names are John Castano, Jeremy Flaum, and Claude Semexant. We are employed by the New York State Department of Public Service (Department). Our business address is Three Empire State Plaza, Albany, New York 12223.

Q. Mr. Castano, what is your position with the Department?

A. I am an Auditor Trainee 2 in the Office of Accounting, Audits and Finance.

Q. Please briefly describe your educational background and professional experience.

A. My educational background and professional experience is discussed in my direct testimony in this proceeding.

Q. Mr. Flaum, what is your position with the Department?

A. I am employed as a Utility Analyst 3 in the Environmental Certification and Compliance Section of the Office of Electric, Gas and Water.

Q. Please briefly describe your educational

background and professional experience.

A. I graduated from the State University of New York College at Cortland in 2003 with a Bachelor of Science degree in Geology. I also received a Master of Science degree in Environmental Management from the University of Maryland, University College, in 2008. I joined the Department in 2009. Prior to joining the Department, I held Geologist positions at two environmental consulting firms where I performed field investigations, oversight, and data analysis for multiple environmental remediation sites.

Q. Please describe your responsibilities with the Department.

A. My primary responsibilities include evaluating environmental and community impacts and construction feasibility issues for electric and gas transmission facilities and electric generating facilities under Article VII and Article 10 of the New York State Public Service Law. Additionally, I have been assigned to review SIR matters and provide recommendations for previous cases before the Public Service

Commission of the State of New York (Commission).

Q. Have you provided testimony in previous Commission proceedings?

A. Yes. I previously testified as part of Department Staff's SIR Panels in the following proceedings: Cases 13-E-0030, 13-G-0031 and 13-S-0032, Consolidated Edison Company of New York, Inc.; Cases 14-E-0318 and 14-G-0319, Central Hudson Gas & Electric Corporation; Cases 14-E-0493 and 14-G-0494, Orange and Rockland Utilities, Inc.; 15-E-0283, et al., New York State Electric and Gas Corporation and Rochester Gas and Electric Corporation; Cases 16-G-0058 and 16-G-0059, KeySpan Gas East Corporation and The Brooklyn Union Gas Company; and Cases 16-E-0060 and 16-G-0061, Consolidated Edison Company of New York, Inc. I have also testified before the Commission regarding the water quality issues and environmental impacts of proposed electric transmission projects in Cases 08-T-0034 and 10-T-0139.

Q. Mr. Semexant, what is your position with the Department.

A. I am a Utility Engineer 1 currently assigned to the Gas Policy and Supply Section of the Office of Electric, Gas and Water of the New York State Department of Public Service.

Q. Please briefly describe your educational background and professional experience.

A. I attended Dutchess Community College and graduated with an Associate Degree in Applied Science. I continued my education at SUNY Buffalo and in June 2010 graduated with a Bachelor of Science degree in Civil Engineering. From April 2006 to December 2009, I was employed by The New York State Department of Transportation as a construction inspector. I was responsible for a number of tasks which included inspections of major roadway projects and other construction projects. In March 2012, I joined the Staff of the Office of Electric, Gas and Water as a junior engineer, where I have performed various engineering analyses and review of various petitions and tariff filings of water and electric utility companies in New York State.

Q. Please describe your responsibilities with the

Department.

A. My work at the Department primarily involves analyzing water and gas utility submittals as they pertain to operation and maintenance expenses, gas expansion and rate design.

Q. Have you provided testimony in previous Commission proceedings?

A. Yes. Most recently I have testified as part of Staff's SIR Panel and Gas Network Enhancement Panel in Cases 14-E-0493 and 14-G-0494, regarding Orange and Rockland Utilities, Inc.; Cases 16-G-0058 and 16-G-0059, KeySpan Gas East Corporation and The Brooklyn Union Gas Company; and Cases 16-E-0060 and 16-G-0061, Consolidated Edison Company of New York, Inc.

Q. In your testimony, will the SIR Panel refer to, or otherwise rely upon, any information produced during the discovery phase of this proceeding?

A. Yes. We will refer to, and have relied upon, several responses to Department Staff Information Requests (IRs). The IRs that we rely upon are included in Exhibit__(SIR-1).

Q. Are you sponsoring any other exhibits to accompany your testimony?

A. Yes. Exhibit__(SIR-2) provides a detailed summary of our adjustments to the Company's proposed SIR recovery and rate year rate base.

Q. Briefly describe the regulation and oversight of SIR programs in New York State.

A. SIR programs are primarily overseen by the New York State Department of Environmental Conservation (DEC), in accordance with 6 NYCRR Part 375 regulations. The United States Environmental Protection Agency (EPA) regulates and oversees federal Superfund sites. Under orders or agreements with utilities, DEC regulates the cleanup of former manufactured gas plant (MGP) sites within the State.

Q. Please summarize the scope of the SIR Panel's testimony.

A. We summarize our review of the SIR program and costs of the National Fuel Gas Distribution Corporation – New York Division ("Distribution" or the "Company"). We reviewed the Company's SIR practices, historic and forecasted expenditures, and rate allowance request. We then present our findings regarding the reasonableness of the Company's projected SIR

expenditures and proposed rate allowance related to the recovery of its SIR program costs; the effectiveness of the Company's SIR cost mitigation strategies and procurement practices for SIR work; and the Company's compliance with regulatory requirements applicable to its SIR sites.

Q. What costs are included in the Company's SIR program?

A. These expenses primarily relate to the costs of assessment, monitoring, cleanup and restoration of sites containing environmental contamination for which the Company has been found to be wholly or partially responsible pursuant to the Federal Comprehensive Environmental Response, Compensation and Liability Act of 1980 (Superfund) and the Company's Consent Orders with the DEC to perform SIR activities associated with the cleanup of environmental contamination resulting from the operation of MGP sites owned or operated by the Company and its predecessor companies.

Q. How many sites are currently included in Distribution's SIR Program?

A. According to the testimony and exhibits of witness Hartz, Distribution is a Potentially Responsible Party (PRP) for one federal Superfund site – York Oil – and is currently wholly or partially responsible for seven MGP sites: Bradley/Westwood, Buffalo Service Center, Former Buffalo Service Center – Offsite, Mineral Springs Works, Tonawanda, Dunkirk, and Hornell.

Q. Are there additional SIR sites for which the Company is aware of potential future liabilities?

A Yes. According to the Company's 2015 SIR Annual Report, incorporated with the Hartz testimony as Exhibit__(LEH-1), Distribution received notification in a letter from DEC dated August 21, 2008, of eight MGP "locations of interest" in the Company's service area. The testimony of witness Hartz and the 2015 SIR Annual Report indicate that Distribution holds responsibility at two of these sites - Dunkirk MGP and Hornell MGP - both of which are included in the list of the Company's current SIR sites previously identified in our testimony. Further, Distribution received a letter from DEC dated

June 22, 2010, indicating that no additional research or investigation is needed at the Fredonia former MGP site. A copy of this letter was provided in the Company's response to IR DPS-201, included in Exhibit__(SIR-1). No formal determinations of liability for the remaining five sites have been made.

Q. Please identify the remaining five sites and describe the nature of the contamination for which the Company may be responsible.

A. The other sites identified by DEC are the Jamestown, Salamanca, Niagara Falls, Batavia, and Westfield former MGP sites. Although DEC indicated in its letter dated August 21, 2008, that it is currently evaluating potential environmental contamination associated with former manufactured gas operations at these sites, other sources of contamination may also be identified during the course of investigations.

Q. Has Distribution incurred costs relating to the investigation or remediation of any of these five sites?

A. According to Distribution's response to IR DPS-

201, the Company has spent approximately $72,000 since 2011 for investigating its potential liabilities at these sites. These costs were not tracked individually for each site because much of the costs incurred during this preliminary stage are common to multiple sites.

Q. Does the Company expect to incur costs relating to SIR activities for any of these sites in the rate year?

A. No. Distribution indicates in its response to IR DPS-201 that the DEC's review and assessment of these sites is ongoing. While the Company may incur some minor costs in response to informational needs of the DEC, no significant costs relating to investigation and remediation of these sites are anticipated in the rate year.

Q. Are there any environmental contamination sites for which the Company has completed remedial activities or is otherwise no longer responsible for SIR costs?

A. Yes, the Company was previously responsible for SIR activities at a number of other sites, including multiple PRP sites. According to Table 1 of its 2015 SIR Annual Report,

Distribution has spent approximately $4 million in total costs for sites previously completed. However, because the Company is no longer incurring costs for those sites, they are not discussed further in our testimony.

Q. What is the Company's forecasted SIR deferral balance at March 31, 2017?

A. The Company's forecasted deferral balance at March 31, 2017 is $15,832,000.

Q. Is the Company proposing any offsets to the SIR deferral balance?

A. Yes. The Company is proposing to apply the balance of residual deferred credits totaling $1,002,000 to the SIR deferral balance at the start of the Rate Year.

Q. Did the Company include the residual credits of $1,002,000 in their SIR deferral forecast calculation?

A. No. Referring to Company's response to DPS-43, included in Exhibit__(SIR-1), it states "The proposal to apply the deferred credits to the SIR balance was not reflected in Exhibit (RMFA-2) Schedule 3 sheet 3 to appropriately reflect both proposals (SIR and Settlement Deferrals) as

stand-alone."

Q. Does the Panel agree with the Company's proposal to apply the residual credits of $1,002,000 to the SIR deferral balance at the start of the Rate Year?

A. Yes. We applied the residual deferred credits totaling $1,002,000 to the Company's forecasted deferral balance of $15,832,000, resulting in a forecasted deferral balance of $14,830,000 at March 31, 2017. This adjustment also reduces the Company's average balance rate year rate base by $609,000 (net of tax).

Q. What is the Company's forecast of SIR expenditures in the Rate Year?

A. The Company is projecting approximately $854,000 of SIR expenditures to be incurred during the rate year.

Q. How did Distribution project these costs?

A. On page 8, of her direct testimony, Ruth Friedrich-Alf states, "My forecasted expenditures are based on the assumptions and estimates that were the foundation of the information contained in the Annual Report Concerning the Status of Investigation and

Remediation Costs, Schedules and Regulatory Compliance which was filed with the Commission on March 31, 2016."

Q. Please explain the Company's proposal for recovery of SIR expenditures during the Rate Year.

A. Distribution is reflecting an incremental $3,000,000, increasing their current SIR recovery of $2,000,000 to $5,000,000 in the rate year.

Q. Please explain the Company's rationale for increasing their SIR recovery by an incremental $3,000,000?

A. According to the Company's response to DPS-40, the Company is proposing a rate allowance for SIR of $5,000,000 to balance the need for rate relief and the impact on customers, with the objective to reduce the deferral balance of monies owed by the ratepayer to the company.

Q. Do you agree with the Company's proposal to recover an incremental $3,000,000, increasing their current SIR recovery of $2,000,000 to $5,000,000?

A. No. The Company did not provide a calculation

supporting the incremental $3,000,000, for a total rate year recovery of $5,000,000

Q. What do you recommend regarding the Company's recovery of SIR costs?

A. We recommend a straight-forward calculation, by segregating SIR recovery into two components; current cost recovery, and amortization of the deferral balance. For the first component, we recommend recovery of the forecasted SIR expenditures to be incurred during the rate year of $854,000. For the second component, as discussed above, we agree with the Company's proposal to apply residual credits to the forecasted deferral balance resulting in a net balance of $14,830,000, and recommend a 5 year amortization period, for a rate year recovery of $2,966,000. Our calculation provides adequate support for our proposed rate year level of recovery for SIR.

Q. Why are you recommending a formal calculation when determining the rate year levels for SIR recovery?

A. Our proposal is supported by the calculations properly accounting for amortization of the

deferral balance and collection of costs to be incurred during the rate year.

Q. Please quantify your adjustment.

A. Our adjustment reduces the Company's rate year O&M forecast by $1,180,000 for total SIR recovery of $3,820,000. In addition, since we are reducing the level of amortization, our adjustment increases the Company's average balance rate year rate base by $269,000 (net of tax).

Q. Has the Panel prepared any exhibits to support the proposed adjustment?

A. Yes, Exhibit__(SIR-2) provides a detailed summary of our adjustments to the Company's proposed SIR recovery and rate year rate base.

Q. Has the Panel reviewed the forecasted activities and costs for each of the Company's SIR sites?

A. Yes, we have reviewed the testimony and workpapers applicable to the SIR programs and costs of Distribution. Based on our experience in examining costs associated with similar SIR activities, we conclude that the projected costs are reasonable and generally consistent with the anticipated scopes of work for each site.

Q. Has Distribution demonstrated that its SIR program is in compliance with all applicable regulatory requirements and timetables?

A. Yes. Company witness Hartz indicates that each of its sites are in compliance with existing timetables and DEC requirements.

Q. How are SIR activities for the utilities' MGP sites within New York State prioritized?

A. In consultation with the New York State Department of Health, DEC's prioritization of remedial activities at MGP sites is ongoing. DEC prioritizes sites based on several considerations, including existing land use of the site and nearby properties, proximity of the site to sensitive environmental receptors, cultural and recreational resources in close proximity to the site, reliance on private and public water supply wells in close proximity to the site, and potential reuse of the site.

Q. Please summarize your understanding of the Commission's Order Concerning Costs for Site Investigation and Remediation, issued November 28, 2012, in Case 11-M-0034 (SIR Order).

A. During that proceeding, the Commission

considered the possibility of adopting a generic policy with respect to the sharing of SIR costs between ratepayers and shareholders. The Commission concluded that a generic cost-sharing requirement should not be applied; however, the Commission stated that cost-sharing should be considered in future rate cases if it is determined that a utility is not exerting appropriate efforts to control SIR costs. The SIR Order required the joint major electric and gas companies to collaborate and file with the Commission an inventory of best practices for SIR cost containment. In addition, the SIR Order required that, in any future rate filing in which a utility seeks to recover SIR expenses, the utility must provide testimony discussing its SIR cost control efforts and include an attestation to the utility's compliance with the inventory of best practices for SIR cost containment. Furthermore, the SIR Order directed that testimony be provided establishing that the remediation process is in compliance with existing timetables and DEC requirements, explaining the results of any

internal process the utility may have conducted to review its SIR procedures, and describing how internal controls are utilized for SIR projects.

Q. Does Distribution describe its practices and strategies for reducing and/or minimizing SIR costs?

A. On Page 7 of his testimony, witness Hartz provides an attestation that the Company's SIR program comports with the Inventory of Best Practices for Utility SIR Programs, filed March 28, 2013, in Case 11-M-0034, pursuant to the Commission's direction in the SIR Order. The cost control efforts utilized by Distribution for its SIR programs are described in witness Hartz's testimony and in the Company's 2015 SIR Annual Report.

Q. Describe the competitive bidding and procurement processes for consultants and remediation contractors utilized by Distribution for its SIR program.

A. The processes for the competitive bidding and procurement of consultant and remediation contractor services for the SIR program are described in the Company's Procurement Manual,

included as an attachment to the 2015 SIR Annual Report. Based on the information provided, we understand that Distribution uses a competitive bidding process to procure consultant and remediation contractor services for all of its SIR sites. The procurement processes for both environmental consultants and remediation contractors involve the same general process, which includes a project-specific request for proposals. Requests for proposals for SIR work are distributed to pre-qualified consultants and contractors.

Q. Do the procurement and competitive bidding practices described by Distribution enable it to effectively implement its SIR program while mitigating consultant and remediation contractor costs?

A. Based on the information provided by the Company in this proceeding, we believe that the consultant and remediation contractor procurement and competitive bidding practices enable it to effectively carry out the SIR programs, while utilizing competitive bidding processes that minimize costs for individual

sites.

Q. Does Distribution utilize any other mechanisms for reducing and/or minimizing SIR costs?

A. Yes. The testimony of witness Hartz, including the Company's 2015 SIR Annual Report, and the responses of Distribution to IRs in this proceeding identify several cost control efforts that are utilized in the SIR programs. The Company's cost control efforts include internal oversight of SIR activities, costs and procurement practices, utilization of waste minimization techniques and reuse of excavated materials, and coordination with DEC to implement remedial plans that contemplate the current and intended future uses of properties.

Q. Does Distribution perform audits or other internal reviews of its SIR Program or individual SIR sites?

A. According to the Company's response to IR DPS-113, included in Exhibit__(SIR-1), there have been no internal or external audits of the Company's SIR program or individual sites over the past five years. However, SIR expenditures are subject to review under the Company's

internal testing for Sarbanes-Oxley compliance and there have been no reported issues with any of the invoices or expenditures made under the SIR program to date. Additionally, the SIR program is discussed quarterly with upper level Company executives, is a standing agenda item for the Disclosure Committee of the Company, and invoices and expenditures associated with the SIR program are reviewed by Distribution's Manager of Environmental Services and Assistant Vice President in charge of Risk Management prior to submittal for payment.

Q. Does Distribution pursue cost-sharing or cost recovery opportunities?

A. Yes. According to the testimony of witness Hartz and the Company's 2015 SIR Annual Report, Distribution routinely performs record searches and forensic studies to determine liability and identify other PRPs.

Q. Describe the results of the efforts by the Company to identify other PRPs at its SIR sites.

A. The Company's efforts for identifying other PRPs at its SIR sites are described in its 2015 SIR Annual Report. These efforts commonly include

review of historical ownerships and operations at the site and neighboring properties for any site that the Company has been identified as a PRP or otherwise has a connection. The efforts of Distribution to identify other PRPs have resulted in identification of other PRPS and a reduction in the Company's overall SIR liabilities.

Q. Does Distribution pursue insurance cost recovery opportunities for investigation and remediation of their MGP sites?

A. Yes, the Company has successfully settled MGP claims with a number of insurance companies. According to the Company's response to DPS-117, included in Exhibit_(SIR-1), Distribution has received a net recovery of approximately $72,600 since the Company's latest rate proceeding in Case 07-G-0141.

Q. Do you agree with Witness Hartz's attestation that the Company's SIR program comports with the Inventory of Best Practices for Utility SIR Programs?

A. Yes. We believe Distribution has provided adequate support demonstrating that its SIR cost

controls are consistent with the Inventory of Best Practices.

Q. Has Distribution satisfied the filing requirements established in the SIR Order in these proceedings?

A. Yes. We believe the Company has generally and sufficiently satisfied the informational filing requirements established in the SIR Order.

Q. Please summarize the SIR Panel's conclusions and recommendations.

A. We conclude that Distribution has provided adequate support for full rate recovery of its SIR program costs. However, as indicated previously, we propose that the Company's recovery allowance for the Rate Year be adjusted to $3,820,000; $854,000 of current cost recovery, and $2,966,000 of deferral amortization.

Q. Does the SIR panel propose any other adjustments or recommendations?

A. No.

Q. Does this conclude the SIR Panel's testimony?

A. Yes, at this time.

A.L.J. LECAKES: Proceed.

BY MS. AISSI: (Cont'g.)

Q. Members of the Panel, did you prepare or identify any exhibits to accompany your testimony?

A. Yes.

Q. Are the documents identified as Exhibits SIR One through SIR Two?

A. Yes.

Q. Do you wish to make any corrections to those exhibits?

A. No.

MS. AISSI: Your Honor, I ask that we mark these exhibits for identification.

A.L.J. LECAKES: Okay. So we'll mark SIR One as Exhibit 281 and SIR Two as Exhibit 282.

MS. AISSI: Thank you, Your Honor.

The Panel is available for cross-examination.

A.L.J. LECAKES: Thank you.

The only party that I have cross-examining is Multiple Intervenors.

Does the company have any cross for this panel?

MR. MILLER: No, Your Honor.

A.L.J. LECAKES: Okay. Go ahead, Mr. Mager.

MR. MAGER: Okay. I think I can be fairly quick.

CROSS EXAMINATION

BY MR. MAGER:

Q. So, in your testimony, you're addressing the company's site investigation and remediation or SIR costs, as well as the appropriate SIR rate allowance, correct?

A. (Castano) That's correct.

Q. Okay. And in this case, NFG's SIR costs relate to the cleanup of manufactured gas plant sites?

A. (Flaum) That is part of the program, yes.

Q. Are -- are any of the sites unrelated to manufactured gas plants?

A. Yes. They do have previous potentially responsible party sites that were not related to manufactured gas plant operations to my knowledge.

Q. Okay. On page eight, you indicate that the company is a potentially responsible party for

one federal superfund site.

Do you see that?

A. Yes.

Q. Is -- is that a manufactured gas plant site?

A. To my knowledge, it is not.

Q. Okay. And then you also indicate that the company was potentially responsible in whole or part for seven manufactured gas plant sites, is that correct?

A. Yes. That sounds correct.

Q. Now, with respect to -- if you could turn to page nine, please.

A. Okay. Just before we get to the next question, I just want to clarify that with the discussion we're having now, is about their active sites, where -- which are listed on their current -- where their -- their most recent 2015 SIR annual report, which was included as an exhibit to the company witness's testimony on this case. There -- there have been other cases that the company has -- other sites that the company has had to address through its SIR program, that are not included in active sites because they've been closed out.

So when I say that, you know, one -- they have one case -- one site that's a non-MGP site, I

mean for their active program, I'm not exactly sure and prepared to discuss what sites they have closed out over the years.

Q. Okay. Thank you for that clarification. I appreciate it.

In -- in fact, let's -- why don't we skip ahead to page thirteen?

Am I correct that the current rate allowance for SIR costs is two million dollars?

A. (Castano) Yes. That's correct.

Q. And skipping ahead to page fifteen, is my understanding correct that Staff is recommending that the rate allowance be increased in this case from two million dollars to 3,820,000?

A. Yes, that is correct.

Q. Am I also correct that the actual SIR cost projected for the rate year on page 14, is 854,000?

A. Yes, that is correct.

Q. So, although the actual -- withdrawn.

Although the projected costs for the rate year are less than half the existing allowance, you're recommending that the allowance be almost doubled in this proceeding, is that correct?

A. Yes. That is correct, but the rate

allowance is not set, based on projection set forth in the rate year. There is also amortization of the forecasted deferral balance.

Q. Okay. With respect to that deferral balance, over what period of time was that created or accumulated?

A. (Flaum) We don't have a specific time period, but our understanding is that it's accumulated over the course of -- I would say at least ten to 20 years.

Q. Okay. So, it was accumulated over ten to 20 years and your proposal is to amortize it over five for this proceeding?

A. (Castano) Yes, that's correct.

Q. Is it fair to say that with respect to at least the manufactured gas plant sites, the -- this cleanup work relates to activities that occurred many, many decades ago?

A. (Flaum) Do -- do you mean the cleanup is for contamination that occurred many years ago?

Q. Yes.

A. Yes, that is correct.

Q. Okay. Why did you pick a five-year amortization period, given that it would result in the

near-doubling of the existing rate allowance, as well as the fact that these costs have been incurred over what you said was a ten to 20-year period?

A. (McAvoy) Well, there's a couple of reasons.

First, given a review at, you know, the company's deferral balance has significantly increased since 2014. There was a -- in a litigated issue in 2007 and a spill in 2014, causing a significant increase in the deferral of about eight million dollars in 2014 and also at a -- looking at project costs going down -- coming down the road for NFG, a five-year amortization seemed reasonable, given current costs and the level the deferral was at and then also to limit the amount of carrying charges in that deferral balance as well.

Q. Now --?

A. (Flaum) I -- I would just add to that response, that the company has additional sites, as discussed in our testimony, are active and they are anticipating remedial construction projects for those sites. You point to, in our testimony, the explanation that next year they're anticipating a total of cost for the program of eight -- approximate eight hundred and something thousand, but if you look at previous years, you

know, there's been years that they've spent four million in costs.

So that's what drives up the deferral balances because you have these remedial construction projects that result in large, heavy costs in a single year.

The company has additional projects that will be coming up, as well as the fact -- and we discussed this in our testimony, there are still five sites, they have been notified, they may have potential liability for and we, you know, so it's a balancing act between trying to prevent huge amounts of costs from showing up down the road and all of a sudden allowing that deferral balance to get out of control. So when you have an opportunity to offset the deferral balance and keep it in check, that was the intent of this panel's recommendation.

Q. When you say you have an opportunity -- was your recommendation based in part on the Staff overall recommended revenue requirement?

A. (McAvoy) Can you rephrase the question please?

Q. Sure.

Did the magnitude of Staff's

recommended revenue requirement impact your proposals in this case in any way?

A. As Jeremy said, given the revenue requirement that Staff proposed and balancing the impact on the ratepayers, I guess you could say it did play a slight factor.

Q. So, if -- if a revenue requirement higher than what Staff is recommending is adopted in this case, that could impact how much you would increase the existing rate allowance too?

A. Can you repeat the question please?

Q. Sure.

To the extent a higher revenue requirement is adopted in this case and by higher I mean higher than what Staff is currently recommending, would that -- could that impact your recommended SIR rate allowance, that you're proposing a near doubling of?

A. Is this a hypothetical question counsel?

Q. Yes. Given that we don't know what the revenue requirement may be at this time, it is.

A. Given the fact that the revenue requirement -- we would not be sure what the revenue requirement is, it would be difficult to set, you know, an

exact amount on any changes that would be necessary going forward at this time.

Q. So again, hypothetically, to the extent the revenue requirement was materially different than what Staff is recommending, that potentially would impact your recommended SIR rate allowance for purposes of this proceeding?

A. (Flaum) I'm not sure that it would, no.

Q. When you say you're not --?

A. The proposed -- the proposed rate allowance that we describe in our testimony is consistent with what we've recommended in, you know, other cases for other utilities. It's consistent with what we think is best practice in terms of, you know, trying to maintain that balance between keeping the deferral balance in check and not allowing it to, you know, not allowing it to get out of control later on, which would have a large impact on ratepayers and avoid excessive carrying charges on the deferral balances.

So, I -- if I understand what you're asking, which is if there was a, you know, a substantial change in the revenue requirement, I'm not sure that we would recommend any changes to what we are proposing for

SIR recovery.

Q. When you're saying you're not sure if you would, does that also mean you're not sure you wouldn't?

A. Well, it's a hypothetical, so -- and you're not giving very clear details on what those changes would be, so it would be impossible for me to give you a definitive answer either way.

But based on the general hypothetical that you are creating, my answer is that it is very unlikely that we would change our recommendation. If you want to provide more specifics, we can get into that, but it doesn't sound like you're asking anything but a general question, so I'm unable to give you anything but a general answer.

Q. I guess I'm trying to figure out to what extent your recommendation to increase the existing rate allowance from two million dollars to roughly three point eight million dollars bears any relationship to the Staff revenue requirement position in this case.

Are you telling me it bears no relationship whatsoever?

A. Our proposal is -- was performed and developed independently of that, if that's what you're

asking.

Q. No, I guess I'm not. I'm asking --.

MR. FAVREAU: I think that does answer your question.

A.L.J. LECAKES: Actually, I -- I agree with Mr. Favreau. I think he did answer the question in the way that he did, but it provided an answer -- maybe not the one you were looking for, but you can ask another question.

MR. MAGER: I -- I fear I might be debating how many angles on the head of a pin at this point, so I'll stop now.

A.L.J. LECAKES: Does anyone else have any cross-examination for this panel?

Panel, what -- carrying charge information a few times. What is the interest rate that's being applied to this deferral?

MR. MCAVOY: The unamortized balance is included in a rate base and the carrying charges on that would be at the pretax rate return.

A.L.J. LECAKES: Okay. Can you say that slower for the record just so --?

MR. MCAVOY: The unamortized balance is included in a rate base and the carrying charges

on that would be at the pretax rate return.

A.L.J. LECAKES: Staff, do you want to approach and see if there's any need for redirect?

MR. FAVREAU: No. There's no need for redirect, your Honor.

A.L.J. LECAKES: All right. Then Panel is dismissed.

Let's go off the record.

(Off-the-record discussion)

A.L.J. LECAKES: We're at six o'clock now.

NFG, can you please call your next witness?

MR. NICKSON: The company calls Eric H. Mainl.

A.L.J. LECAKES: Mr. Mainl, you did identify yourself earlier on the record, correct, as part of a panel?

MR. MAINL: Yes.

A.L.J. LECAKES: All right. I can't remember if I released you or not. Why don't you just stand and we'll swear you again.

Raise your right hand.

Do you swear or affirm that the

testimony you're about to give today is the whole truth?

MR. MAINL: Yes.

ERIC MAINL; Sworn

A.L.J. LECAKES: You may be seated. Go ahead, Mr. Nickson.

DIRECT EXAMINATION

BY MR. NICKSON:

Q. Mr. Mainl, do you have a document entitled Direct Testimony of Eric H. Mainl in front of you?

A. Yes, I do.

Q. Consisting of nineteen pages of questions and answers?

A. Yes.

Q. Was that document prepared by you or under your supervision?

A. Yes, it was.

Q. Do you have any changes or corrections to the testimony?

A. No.

Q. If I were to ask you the same questions today, would your answers be the same?

A. Yes.

MR. NICKSON: Your Honor, I would ask that the direct testimony of Eric H. Mainl be incorporated into the record, as if given orally today. ***

A.L.J. LECAKES: Granted.

That's on the Company's disk for Testimony under the folder NFG Direct Testimony and it will be Mainl Direct Testimony.

*Insert direct testimony of Eric Mainl

BY MR. NICKSON: (Cont'g.)

Q. Mr. Mainl, are you also sponsoring one exhibit to your direct testimony?

A. Yes, I am.

Q. And was that document prepared by you or under your supervision?

A. Yes, it was.

Q. Do you have any corrections to that document?

A. No, I do not.

MR. NICKSON: Your Honor, I ask that the exhibit, which was identified as EHM One be marked for identification.

A.L.J. LECAKES: Okay. That will be number Two eighty-three for EHM One. So that's Exhibit 283.

Is the witness available for cross?

MR. NICKSON: Yes. I'm sorry. Yes.

A.L.J. LECAKES: Mr. Mager?

MR. MAGER: Thank you.

CROSS EXAMINATION

BY MR. MAGER:

Q. Good afternoon.

A. Good afternoon.

Q. Can you please turn to page three of your testimony?

A. I have it.

Q. Okay. At filing, referring to line five, you said the company was proposing overall increase in revenues of 41,697,000?

A. Yes.

Q. Can you -- can you tell me where the company's request stands today?

A. I do not have that exact number with me. I believe it was provided as an interrogatory to Staff.

Q. Okay.

MR. NICKSON: Can you provide the formal -- formally with that IR response at a future time?

MR. DELVECCHIO: I believe it's in -- it's in the view rooms.

UNIDENTIFIED SPEAKER: Yeah. It should be posted in the view rooms.

MR. NICKSON: Okay. Maybe just give me the number and I'll find it when I have it.

BY MR. MAGER: (Cont'g.)

Q. Do you know if it's gone up or down

since --?

A. I believe it's gone up slightly.

Q. Okay. Is it fair to say the -- on a delivery-only basis, the requested increase is about fifteen percent?

A. Approximately.

Q. Okay. Okay. Can you turn to page ten, please?

At the top of the page, do you see where you testify about the company's ability to operate a safe and reliable system, is not enhanced when it's rates are based on a projected total-net revenue that is below what the company received in September 1996?

A. Yes.

Q. Okay. Now, would you agree with me that over the last several years the Commission has issued orders addressing the fact that N. -- NFG's realized rate of return was above its authorized level?

A. The authorized level in previous rate cases, correct.

Q. Okay. In fact, didn't at some point, the -- the Commission step in and make NFG's rates temporary subject to refund because of a concern about its authorized ROE?

A. They issued a show-cause order. That's correct.

Q. Actually my question was poorly phrased.

It -- one of the reasons they offered that -- one of the reasons they issued that was a concern that the company's actual ROE was above its authorized level, is that fair?

A. That is -- that is correct.

The company did not agree with that and the case was ultimately settled.

Q. Okay. But prior -- after issuing the show cause order didn't the Commission subsequently issue an order that made the rates temporary?

A. The rates were made temporary, correct.

Q. And part of the Commission's motivation during that was also the fact that while the company was earning -- or realizing returns above its authorized level, deferrals that would have to be paid by customers were also increasing.

A. I'm sorry. Could -- could you reread that? That -- I can't speak to what the --

Q. Okay.

A. -- Commission's motivations were.

Q. Okay. You know what? I -- I can move on. We -- I guess it'll say what it says.

Could you turn to page 16, please?

A. Okay. I have it.

Q. Okay. Is it fair to say that you're recommending that the Commission reward NFG an ROE at the high-end of the range proposed by its expert?

A. The company's yes.

Q. Are you aware of any decisions by the Public Service Commission involving electric or gas utilities, where the Commission established the ROE at the high-end of the range in recognition of the utility's management or for any other reason.

A. I'm not sure the Commission has issued an order in a litigated rate case, in a number of years.

Q. Well, and I would -- I would agree with you that there -- there haven't been that many.

Are you familiar with any New York State Public Service Commission opinion, that adopted an ROE at the high-end of the range, for whatever reason you're aware of?

A. My -- you're -- you're taxing my memory now, but I do believe in the 1980s or '90s, the --

the concept of rewarding high-performing utilities with an increase in the ROE was recognized and I believe it is also not an uncommon practice in the industry, to recognize and reward high performing utilities with an increased ROE.

And -- and I believe we made this argument in our show cause order. I -- I think -- and I know we made this argument. There is overwhelming evidence in our opinion that ratepayers are -- are better served with a model where utilities establish their rates in a base-rate proceeding, they are allowed to operate their system as efficiently as possible and that they're able to keep the gains of -- of running that efficient system.

And I believe we also said at that time, that the evidence was clear that that was a superior method because our rates stayed flat for a -- a -- a long amount of time, while companies that had an earning-sharing mechanisms and joint proposals, had numerous increases over that time period.

Q. Is it fair to say the Commission, did not adopt the company's arguments in the show-cause proceeding?

A. That case was settled.

MR. MILLER: I think the Commission's show-cause order also did adopt a variant of that argument and I -- I would direct the parties to that.

A.L.J. LECAKES: I'd be interested to read that on brief.

MR. MAGER: Okay. I have nothing further, your Honor.

A.L.J. LECAKES: Mr. Mainl, were you involved at all in the decisions, prior to the show-cause order that NFG made to -- to not file for new rates?

MR. MAINL: I was manager of the department when we made those calculations, yes.

A.L.J. LECAKES: Okay. Bear with me on a hypothetical for a moment.

Assume if you will, that the Commission believed it had the authority to establish an earning-sharing mechanism in a single-year rate order back in 2007 and then that earning-sharing mechanism was in place between 2007 and -- and the show-cause order. If you would, could you speculate whether at the time you believed the company might have come in for rates sooner, if that earning sharing mechanism had been there, or if it might

today still be sitting out without having filed a rate case?

MR. MAINL: Your Honor, I -- I -- I recall similar -- similar lines of -- of cross-examination at the time of the -- of the show-cause order and that's just too speculative. You're -- you're asking what the company's behavior would have been under a totally different set of circumstances.

A.L.J. LECAKES: I -- I can appreciate that. Thank you.

Were you here earlier today when the staff policy panel was being cross-examined?

MR. MAINL: Yes.

A.L.J. LECAKES: I believe it was Mr. Davi on the panel identified 50 basis points for the company as being approximately 2.5 million.

Can you confirm that number?

MR. MAINL: I -- I believe that number would be -- and it -- and it depends on the level of rate base and obviously the return on --.

A.L.J. LECAKES: Right. I was going to ask if --.

MR. MAINL: 5.5 to 6 million dollar range, but we can -- we can provide you the -- the

number based on our initial filing.

A.L.J. LECAKES: Okay. I'm -- I'm curious as to the most recent year that the company filed its annual reports on. Do you know what it was for -- I think, 2015 would be in, so I don't know. Do you know what the value of a single basis points or ten basis points was?

MR. MAINL: Based on the -- based on the settlement, I believe it was closer to the range of six million dollars per hundred basis points.

A.L.J. LECAKES: Okay. I -- I have nothing further.

Is there any need for redirect?

MR. MAGER: I have none.

A.L.J. LECAKES: Yeah. Absolutely.

UNIDENTIFIED SPEAKER: Mr. Ford?

A.L.J. LECAKES: Oh, I'm sorry.

MR. FORD: I -- I have a quick question.

A.L.J. LECAKES: Mr. Ford, yes. Absolutely.

CROSS EXAMINATION

BY MR. FORD: (Cont'g.)

Q. Mr. Mainl, would you agree that the

pressure drop of any fluid through a pipe is proportional to the square of the flow rate?

A. Mr. Ford, I'm not an engineer. I can't answer that question.

MR. FORD: Thank you.

A.L.J. LECAKES: All right. Company may approach.

MR. MAGER: Your Honor, the company doesn't have any redirect.

A.L.J. LECAKES: Thank you, Mr. DelVecchio.

Mr. Mainl, I believe you are excused completely.

MR. MAINL: No, I'm on the --.

A.L.J. LECAKES: You're on the panel tomorrow? The low-income order --

MR. MAINL: Yes.

A.L.J. LECAKES: -- panel?

Okay. I do remember.

MR. MAINL: I'm never excused.

A.L.J. LECAKES: Yeah.

All right. With that, we're going to be adjourned for today. We're going to keep tomorrow's nine a.m. start time.

MR. MAGER: Your -- your Honor, could we spend thirty seconds and go over the order for tomorrow?

A.L.J. LECAKES: Yeah. Absolutely.

We -- we don't need to put that on the record, do we?

MR. MAGER: No.

A.L.J. LECAKES: No?

Okay. So like I said, we'll -- we'll start at nine a.m. and we're adjourned for today, so we're off the record.

(The hearing adjourned)

STATE OF NEW YORK

I, HOWARD HUBBARD, do hereby certify that the foregoing was reported by me, in the cause, at the time and place, as stated in the caption hereto, at Page 1490 hereof; that the foregoing typewritten transcription consisting of pages 1490 through 2300, is a true record of all proceedings had at the hearing.

IN WITNESS WHEREOF, I have hereunto subscribed my name, this the 17th day of October, 2016.