

Before the

TENNESSEE REGULATORY AUTHORITY

**IN RE: PETITION OF ATMOS ENERGY CORPORATION FOR APPROVAL OF A
GENERAL RATE INCREASE**

DOCKET NO. 07-00105

**DIRECT TESTIMONY
OF
MICHAEL D. CHRYSLER**

August 21, 2007

Q. Please state your name for the record.

A. My name is Michael D. Chrysler.

Q. By whom are you employed and what is your position?

A. I am employed by the Consumer Advocate and Protection Division (“CAPD”) in the Office of the Attorney General for the State of Tennessee as a Regulatory Analyst.

Q. What is your educational and work related background?

A. Please reference attached Appendix A for education and work experience.

Q. What is the purpose for your direct testimony?

A. My testimony will deal with certain tariff proposals and operating characteristics of Atmos in Tennessee. My testimony is organized as follows:

I. Bare Steel/ Cast Iron Replacement Compliance

II. The Main Extension Policy

III. Service Metrics & Reporting

IV. Decoupling and the CUA Proposal

V. GTI Funding

I. BARE STEEL/CAST IRON REPLACEMENT COMPLIANCE

Q. Has the Company properly responded to its commitment to the TRA mandate in Docket 05-00258 to replace the remaining bare steel mains at 45,000 feet of main per year?

A. Yes. The Company has communicated to its replacement commitment in response to CAPD Data Request #1, Question 94 for the attrition year ending 10/08 and assumes (although not provided) subsequent years are to be completed as ordered.

1 The Company response:

2 The company was mandated in TRA Docket order 05-00258 dated
3 (sic) to retire 45,000 feet of bare steel main per year until all of the
4 bare main has been removed from service. It is the company's
5 intention to comply with the TRA order.
6

7 Additional response:

8 The bare steel retirement during the attrition period will most likely be
9 done as follows: (replacement schedule November, 2007 through
10 October, 2008 included).
11

12 We can only assume that this good faith commitment will proceed in keeping with the
13 replacement mandate and would request the Company to provide completion updates
14 to our office.

15 II. MAIN EXTENSION POLICY

16 **Q. Please describe ATMOS' proposal to substitute the current Main Extension**
17 **Policy with its new "feasibility model" by company witness Michael H. Ellis.**

18 **A.** The Company proposes to eliminate the minimum line extension¹ currently recovered
19 in rates that provides an opportunity for a free extension allowance equal to 1 foot per
20 Mcf for residential customers. For commercial and industrial customers, the free
21 allowance is dependant on the volume of gas used per year; i.e., if they use less than
22 500 Mcf or less they would get the same per foot allowance tied to their annual Mcf
23 volume. For commercial and industrial consumers using in excess of 500 MCF per
24 year a feasibility analysis would be utilized.

25 Additionally, for customers requiring service in excess of the free limit, Sections

¹ For a complete description of the current policy in service, see **CAPD Exhibit MDC**
T1.

1 7.2.1-3 provide an opportunity for customers to receive a refund of their
2 “contribution” should additional customers be added to the main extension.

3 The proposed “feasibility model” requires “input factors” for determination of
4 profitability, which would have to be verified on a regular basis by TRA Staff. The
5 “Free Extension Allowance” and the five-year opportunity for refund of contributions
6 would be eliminated.

7 **Q. Do you have concerns with the company’s proposal to alter the Line Extension**
8 **policy?**

9 **A.** Yes. The feasibility model appears to be needlessly complex and would require some
10 form of oversight and auditing. Mistakes can be made in the calculation. In addition
11 the discretion that the proposal grants to ATMOS in using the model to “guide” the
12 company’s investment in service to residential customers is somewhat troubling as the
13 proposal lacks guidelines for how the results will be applied to consumers.² I am
14 dismayed that individual residential consumers must show they “will pay, or otherwise
15 justify the cost” of service to their homes.³ Accordingly, should the model be
16 adopted, procedures should be put in place for the TRA staff to audit its application.
17 Bad inputs provide bad “feasibility” analysis and problems for potential customers.

18 **Q. Do you support the proposal?**

19 **A.** No. I would suggest that a reasonable fee-free line extension allowance is both a
20 reasonable obligation to impose on a public utility and an investment in future

² Direct Testimony of Mr. Ellis, p. 8

³ *Id.*

1 earnings for the utility. I believe the current main extension policy should continue
2 as well as the possibility of future refunds based on Section 7.2.3. Since the current
3 “Free Extension Allowance” and “refund opportunity” in Section 7.2.3 are already
4 recovered in base rates, it would appear that the company’s proposal of a “feasibility
5 model” suggests additional ways that customers are required to pay ATMOS for
6 service that is currently paid to the company.

7 The company has not made a convincing case for eliminating the current policy with
8 the compensating benefits to residential and commercial customers especially in a
9 service area with such prolific growth taking place. ATMOS should be promoting
10 such service making growth a part of its strategic vision rather than discouraging it
11 as this proposal suggests.

12 **Q. Are you aware of any other regulatory commission rejecting a similar proposal?**

13 **A.** Yes, the Missouri Commission rejected a similar, recent proposal by ATMOS in Case
14 No. GR-2006-0387 effective March 4, 2007 (**CAPD Exhibit MDC L**).

15 **Q. Can you provide the findings of the Missouri Commission rejecting a similar**
16 **ATMOS proposal?**

17 **A.** Yes, on page 39 of the order (**CAPD Exhibit MDC L**):

18
19 A reasonable fee-free line extension is both a reasonable obligation to
20 impose on a public utility and an investment in future earnings for the
21 utility.

22
23 The Commission agrees with Public Counsel and finds that the main
24 extension policy should not be eliminated at this time. Proposing such
25 a drastic change from 150 feet free to zero feet free is not a reasonable
26 proposal. The Commission finds in favor of Public Counsel on this
27 issue. Atmos shall not implement a new main extension policy.

1 **Q. Do you feel that the proposed Main Extension policy is in the best interest of**
2 **stockholders as well as ratepayers?**

3 **A.** No. The proposed policy adds additional cost and complication in promoting
4 customer growth, which would seem to be at odds with the growth opportunities
5 that ATMOS could promote in its service territory, especially areas such as Franklin
6 and Murfreesboro. In response to Minimum Filing Guidelines #28, Mr. Ellis
7 responded that the annual heating cost for the typical ATMOS customer was \$728.18
8 vs. \$558.85 for the typical cost for a customer using Electric Heat pump or about
9 30% more expensive to heat with ATMOS gas at current rates. With such a
10 significant cost disadvantage with its electric competitor, one might suggest that
11 prudent management would be promoting growth opportunities rather than reducing
12 them through a more onerous extension policy.

13 **III. SERVICE METRICS AND REPORTING**

14 **Q. What is your opinion regarding the need for service metrics?**

15 **A.** The Company, the TRA and other interested parties do not have the benefit of
16 measurable data to effectively monitor the quality of customer service. Recent
17 experience has shown that problems in service and operations rarely come to the
18 attention of the TRA and other interest parties until it is too late to avoid harm.

- 19 a. Alleged meter reading violation in TRA Docket 05-00150 (see
20 attached **CAPD Exhibit MDC D1** Settlement Agreement) Alleged
21 Violations of Tenn. Code Ann. Section 65-4-12- (2004) and Rules of
22 The Tennessee regulatory Authority, Chapters 1220-4-5-.08 And
23 1220-4-5-.09 By ATMOS Energy Corporation, ending in a \$25,000
24 payment in settlement with a \$15,000 contribution to Murfreesboro
25 community organizations.

- 1 b. Formal Notice of Violations, ATMOS Energy Murfreesboro Incident
2 8/2/05, Report of Natural Gas Safety Inspection #05-267, Docket No.
3 05-00323 **CAPD Exhibit MDC D2.** Hospitalization of a company
4 employee resulting from the ignition of natural gas escaping from a
5 construction incident involving two company employees. A civil
6 penalty was assessed for \$13,000 Exhibit D2 (final page) and D3 for
7 failure to adhere to safety standards as outlined on p. 3 of Exhibit D3
8
- 9 c. TRA Docket 05-00323 (see attached **CAPD Exhibit MDC D3 -**
10 Murfreesboro Incident - August 2, 2005. Order Approving Proposed
11 Civil Penalty And Accepting Response Offering Long Term
12 Corrective Actions.
13
- 14 d. **(CAPD Exhibit MDC D4)** IN RE: Alleged Violations By ATMOS
15 Energy Corporation of Stipulations Adopted In Docket NO. 05-00281
16 and 07-00152. Contribution of \$30,000 in settlement of inappropriate
17 termination of 33 customers between 11/01/05 and 3/31/06.
18

19 While the compiling and reporting of service metrics may not have avoided some of
20 these violations and incidents, recording and monitoring such data can avoid a
21 downward trend in service and safety and prevent problems from escalating into
22 serious matters brought to the attention of the TRA. Service metric reporting can be
23 used to detect problems in sufficient time to correct and avoid serious consequences,
24 thus service metric reporting may contribute to the efficiency of the company. The
25 LDCs under the TRA's jurisdiction should work with the Authority, TRA Staff, and
26 Tennessee Attorney General staff to identify and develop a set of metrics which will
27 effectively measure service quality. Regularly reporting service metrics will provide
28 a clearer picture to the TRA of the level of service and safety either enjoyed or
29 tolerated by Tennessee consumers.

30 IV. DECOUPLING

31
32 **Q. The Company has proposed a CUA mechanism which will decouple revenues**

1 **from volume sales. Are you opposed to it?**

2 **A.** Yes, the concept of decoupling as embodied in the Company's proposal is not in the
3 public interest. My testimony will first address the general concept of decoupling and
4 then move to an analysis of the specific company CUA proposal.

5 **Q.** **Please summarize your opinion regarding decoupling.**

6 **A.** Decoupling as a concept will in practice erode the matching principal that is the
7 foundation of rate of return regulation. It fails to take into account the revenues
8 generated by customer growth and other factors that produce revenue or savings in
9 other aspects of operations, which offset financial loss attributed to conservation.
10 Decoupling sets a benchmark, which according to company forecasts, will in practice
11 produce an annual rate increase for consumers. Each year the mechanism is in place
12 will produce a rate increase greater than the preceding year. Without the safeguard
13 of an earnings cap, the Company will, absent extraordinary circumstances, receive a
14 financial windfall annually. And a decoupling mechanism is not a tool to encourage
15 conservation. It simply guarantees revenue without regard for other factors and other
16 revenues and savings, thus greatly reducing the risk of stockholders to the detriment
17 of consumers. Consumers will receive no benefit at all in contrast to the company.
18 In fact, a Hearing Officer in New Mexico called one decoupling proposal a "windfall"
19 for the company in a Recommended Decision⁴ in which the state commission adopted

⁴ MDC G1, *Recommended Decision of the Hearing Examiner*, Case No. 06-00210-UT, p. 116.

1 the conclusion rejecting the decoupling proposal⁵.

2 An additional concern is a decoupling mechanism is an additional tracker (or portion
3 of a tracker already in place) which adds more burden to Staff and to company
4 personnel. Mistakes made in company reporting may result in disputes and contested
5 case proceedings causing a financial and resource burden on regulatory bodies,
6 interested parties and the company.

7 Other experts have testified that trackers such as a decoupling mechanism should only
8 be adopted in the face of compelling circumstances.⁶ As my testimony will later
9 show, the revenue generated by customer growth offsets any loss attributed to the
10 decline in usage per customer. Thus, the circumstances appear to be far from
11 compelling.

12 **Q. Is decoupling a departure from traditional rate making principles?**

13 A. Yes. Decoupling is a departure from traditional rate making, including the “matching
14 principle”. Decoupling substitutes new “regulatory fictions” to guarantee revenue
15 while ignoring other rate making factors.

16 **Q. Are SFV (Straight Fixed Variable) and Revenue Decoupling Related?**

17 A. Somewhat. A Straight Fixed Variable rate design makes customers pay a flat monthly
18 fee based on a developed number by a proposing utility and approved by a regulator,
19 but it is not truly the measured value of product delivered to a specific customer.

⁵ MDC G, *Final Order Partially Adopting Recommended Decision*, Case No. 06-00210-UT, p. 39-40.

⁶ MDC F - Direct Testimony of Michael Brosh, p. 7.

1 There is no “volumetric” component involved in the rate other than to pay for the gas
2 purchased from the pipeline supplier.

3 Revenue decoupling usually preserves the traditional rate design structure utilized by
4 most regulatory commissions around the U.S., namely, distribution service rates are
5 comprised of a fixed customer charge and a volumetric distribution charge. However,
6 a decoupling mechanism sets a target revenue-per-customer level to be recovered
7 under these rates. If actual recovery falls below the target, then rates are increased
8 in a subsequent period to make up for the shortfall and vice-versa. Thus, one can
9 think of revenue decoupling as creating a true-up process that sets variable rates at
10 a level that makes customers indifferent between them being fixed or variable. SFV
11 can be thought of as “perfect revenue decoupling” since rates are not required to be
12 “trued-up” in any given year and are directly (not indirectly) charged to customers on
13 a fixed per-customer basis⁷.

14 **Q. What is the “Matching Principle” and why is it such an important component**
15 **in traditional ratemaking?**

16 **A.** The Matching Principle embraces the importance of recognizing all revenues and
17 costs during a period of time to determine any needed changes in pricing. Under the
18 Matching Principle it is essential that there be synchronized and harmonious review
19 of both revenue and cost levels occurring within a carefully structured test period.
20 This type of review is necessary because both revenues and costs are dynamic,

⁷ MDC E - Direct testimony and Exhibits of David E. Dismukes, Ph.D on behalf of the Michigan Attorney General in MPSC Case No. U-14893, November 13, 2006, p.11-12 (**CAPD Exhibit MDC E**).

1 customers are added and lost, inflation and productivity changes impact costs, capital
2 market conditions change and sales volumes fluctuate. State commissions and experts
3 have expressed the same principle.⁸

4 **Q. How does a Decoupling Mechanism such as the Company's Proposal violate the**
5 **Matching Principal?**

6 **A.** A decoupling mechanism focuses strictly on one issue affecting revenue while
7 ignoring other factors, such as the impact of customer growth on revenues or the
8 relationship that revenues have to expenses and net plant. A mechanism such as the
9 proposed CUA is intended to recover the amount of lost "margin" per customer due
10 to conservation (or any other reason including economic downturns, government
11 efficiency standards, "dialing-down" or other reasons) while ignoring the revenue
12 impact of customer growth which offsets such "losses". Singling out one factor and
13 ignoring others is simply inappropriate and results in piece-meal or "single issue rate
14 making". Decoupling simply fails to take into account other revenues from customer
15 growth and savings from aspects of operations.

16 Once more, traditional rate of return regulation requires that a company's revenue
17 requirement be based on the detailed analysis of rate base, operating income, and
18 allowed rate of return. Thus, a company's "revenue requirement" is the result of the
19 process of rate-making, which can be illustrated by the following formula:
20

⁸ MDC F - Direct Testimony of Michael Brosh, p. 4-14, MDC E - Direct testimony and Exhibits of David E. Dismukes, Ph.D on behalf of the Michigan Attorney General in MPSC Case No. U-14893, November 13, 2006, p.3-5, 25-27

1 Revenue Requirement = Rate Base x Rate of return + Income Tax Allowance +
2 Operating Expense + Depreciation⁹
3

4 All of the elements of the formula are dynamic and subject to change. And they are
5 subject to scrutiny in a rate case. If a utility company, after the completion of rate
6 case, filed for another rate case immediately afterwards, the basic elements such as
7 rate base would be different. There are no fixed points in rate making. Fixed levels
8 of “authorized revenues”, which decoupling essentially achieves, do not exist within
9 the realm of rate of return regulation. It is the “revenue requirement”, not “authorized
10 revenues”, that is set in a rate case. In applying the matching principal, a test year
11 should take into account foreseeable changes. In this context, declining usage per
12 customer, as well as new revenues generated by customer growth and other factors,
13 are built into the revenue requirement. Accordingly, decision makers determine in
14 each rate case the extent of revenue losses attributed to conservation and whether
15 such losses are being offset by revenue from customer growth or other factors. A
16 decoupling mechanism, on the other hand, arbitrarily ignores other factors that may
17 offset any losses attributed to the decline in usage per customer.

18 **THE ATMOS “CUA” PROPOSAL:**

19 **Q. Mr. Gary L. Smith presents ATMOS’ proposed decoupling mechanism “CUA”**
20 **or Customer Utilization Adjustment, would you please discuss the company’s**
21 **rate re-design proposals?**

⁹ Davidson, Sidney. *Handbook of Modern Accounting*, 3d. (Chapter 40: Accounting for Rate-Regulated Enterprise) p. 40-6.

1 **A.** Yes, Mr. Smith states in his testimony that the company filed a similar proposal in
2 Docket No. 05-00258 by M. Patricia Childers; however, “the Company has revised
3 its proposal in this case similar to what was proposed to the Tennessee Regulatory
4 Authority (TRA) recently by Chattanooga Gas Company.”

5 **Q.** **Does Mr. Smith detail either the specific differences between their prior and**
6 **current decoupling proposal or the similarities to the Chattanooga Gas**
7 **Company proposal?**

8 **A.** No, Mr. Smith did not provide any obvious analysis of their changed proposal or
9 specific similarities with the CGC proposal.

10 **Q.** **Does Mr. Smith explain how the CUA would be calculated?**

11 **A.** Yes, as explained in his testimony on page 7 lines 1-8,
12 ATMOS Energy’s CUA, as set forth on the company’s proposed
13 Original Tariff Sheet No. 51.1, would, annually, compare the actual
14 non-gas revenues per customer for each applicable rate schedule,
15 including the WNA revenue, to those established in this docket. The
16 resulting difference within each class then would be multiplied by the
17 actual number of customers, to determine the excess revenue to be
18 refunded to, or the revenue deficiency to be collected from, each class.
19 The excess or deficiency then would be divided by the annual
20 projected volume for each class, to determine the CUA charge or
21 credit rate.

22
23 **Q.** **But Mr. Smith suggests the CUA will be subject to a true-up to prevent over or**
24 **under collecting from consumers. Does the “true-up” mean that the Company**
25 **will not over- earn by traditional rate- making principles?**

26 **A.** No. The “true-up” only implies a reconciliation adjustment between the actual
27 revenue per customer vs. a benchmark revenue per customer multiplied times the

number of customers, which creates a deferral (similar to the ACA deferral) to be distributed in a future period (again as the ACA). Since there is no proposed earnings cap or any limitation included in the proposal, the company has no mechanism which would prevent the CUA from reaping financial windfalls for the stockholders.

Q. Did Mr. Smith provide an example of how the Company’s proposed “true-up” would work?

A. Yes, continuing response to CAPD Data Request #1, Q.96:

Assuming the Company is granted its rate design proposed in this Case, the average residential revenue (excluding gas costs) is \$255.22 (reference Exhibit PJC-1). This would become the benchmark average margin per customer in rate class 210 for purposes of the CUA.

In the first year of the CUA, the company would compute the actual margin by rate class, including WNA revenues. For illustrative purposes, assume the average revenue per customer in rate schedule 210 for the first year was \$260.00. If there were 114,000 customers in that rate schedule, the total CUA would equal $(\$255.22 - \$260.00) \times 114,000$ or -\$544,920. Assume the company projected customer volume for the class is 600 ccf. Then the CUA credit rate to be applied would be -\$0.0080 per ccf for the upcoming year.

In the second year, the same comparison of the actual margin by rate class would take place. The “true-up” however would additionally compare the actual CUA revenues collected to the intended credit of \$544,920 during the year. Because the CUA is applied to the volumetric rate, actual volume variations to the projected 600 ccf will cause an over-or under-collection of CUA revenues. For purposes of precision, the annual cumulative true-up mechanism will correct for these variances; similar to the ACA (actual cost adjustment) in the PGA (purchase gas adjustment) rider.

Q. Does the example presented by Mr. Smith in his testimony present an example reflect the current usage parameters in place, as previously identified by

1 **ATMOS?**

2 **A.** No, Mr. Smith's example is not consistent with his reasons for promoting the CUA.
3 The example provided by Mr. Smith is an unlikely scenario since it calculates a **credit**
4 to consumers based on a 1.9% **increase** in average revenue per customer (\$260.00
5 - \$255.22), thus providing a potentially misleading example of how the CUA would
6 work. Given the testimony of Mr. Cagle and his forecast or estimate of a **declining**
7 usage factor of 1.5%, Mr. Smith's consumer friendly example is not realistic and out
8 of step with the company's projections.

9 **Q.** **Do you have an example of how the CUA would work using realistic parameters**
10 **previously exhibited by the Company?**

11 **A.** Yes, **CAPD Exhibits MDC C1 - C7** utilizes the data provided in ATMOS' Exhibit
12 PJC-1 as similarly referenced by Mr. Smith's example and adjusting the rate
13 calculation components with a growth rate of 2.1%¹⁰ per year for all three revenue
14 classes and a reduction in usage of 1.5% per year. My worksheets detail and project
15 customers, Ccf, revenue, CUA (decoupling) revenue utilizing the previously
16 mentioned benchmark year for four years subsequent to the benchmark year.

17 **Q.** **How are the projected years data calculated?**

18 **A.** Each revenue class is calculated on a separate worksheet; Residential (Exhibit C3),
19 Commercial (Exhibit C5) and Public Authorities (Exhibit (C7)). For illustrative
20 purposes I will be utilizing the worksheet for Residential Class, Exhibit C3. Lines 1-4
21 were taken from ATMOS Exhibit PJC-1 and for ease, documented as MDC Exhibit

¹⁰ 2.1% was used to be consistent with the customer growth rate proposed with Atmos.

C8, using the rates identified in Original proposed Sheet No. 51.1 (CAPD Exhibit MDC C9).

Customers: Customers are calculated growing at 2.1% each year with the increase in customers reduced $\frac{1}{2}$ in the first year to reflect customer additions spread throughout the year.

Ccf calculation: Ccf is calculated at a reduction of 1.5% each year although I have calculated the volumetric increase in Ccf increased as new customers are added annually.

Revenues are calculated using the PJC-1 proposed rates and extended at projections made within the spreadsheet.

Calculation of the CUA: Calculation of the CUA is made on Exhibit C2, C4, C6 with source data originating from Exhibits C3, C5, C7 calculated in a manner as documented by Mr. Smith in response to CAPD DR #1, Q.96

Summary of projections: A summary of all revenue classes are brought forward to Exhibit C1 detailing CUA Revenue, Annual revenue growth summary of CUA and growth revenue.

Q. What conclusion does your exhibit suggest?

A. The projection provides an interesting comparison that although use per customer is decreasing at 1.5% per year (including new customers) the additional growth in customers, more than offsets the reduction in use per customer.

Revenue: The customer charge amounts to approximately 55% of total projected revenue for the residential class, 30% for commercial and approximately 37% for

1 public authority. Average Annual Revenue Per Customer column (m) reflects the
2 differences in revenue per customer by rate: 210 RGS Summer \$149, 210 RGS Sr
3 CIT Summer \$29, and 210 RGS Sr CIT Winter (weather sensitive) \$174 which
4 reflects that the average rate for 49,145 customers would be billed less than the
5 revenue class average of \$251.11 for the Benchmark year.

6 **Analysis of CAPD Exhibit MDC C1**

7 Demonstrating the average revenue per customer using the company's revenue
8 projections in exhibit PSC-1 clearly demonstrates how unfair this proposal is. The
9 proposal clearly asks all customers to pay additional revenue when customers
10 conserve, while forgetting to consider the revenue growth due to new customers. By
11 Projected Year 4, the CUA Revenue for the Residential class is \$950,000¹¹ that will
12 be allocated to all applicable customers within this residential class. Ccf Use and
13 Revenue Growth mushroom to \$30,199,985¹² total revenue. While Ccf reductions
14 from use per customer amounts to a reduction of 4,256,007¹³ and additional Ccf from
15 new customers (customer growth) amounts to 5,053,185¹⁴, generating an annual
16 revenue growth of \$495,805¹⁵ with total residential revenue in excess of benchmark

¹¹ MDC C2, column (h) line 11

¹² MDC C3, column(l) line 32

¹³ MCC C3, column (f), line 32

¹⁴ MDC C3, columns (d) and (e), line 32

¹⁵ MDC C1 column (b), line 19

1 of \$2,484,755¹⁶ - all from customer growth before the CUA. The worksheet
2 identifies how reductions in use per customer are overcome by customer growth for
3 both Ccf sold and revenue billed prior to the calculation of the CUA adjustment.

4 **Q. Has ATMOS proposed any Earnings Cap or other “ceilings” to keep a**
5 **continuity between growing CUA revenues plus revenue achieved through**
6 **normal growth ?**

7 A. No. The revenue from the impact of customer growth is ignored by the CUA.
8 Without some type of restriction, the new proposal would probably allow the
9 company to make revenues in excess of the “benchmark” (discussed previously).
10 Please note MDC C1 lines 4, 10, 16,21 which indicates that by the end of Projected
11 Year 4, ATMOS would be making almost \$4,000,000¹⁷ over the benchmark
12 calculated in Ms. Childers exhibit PJC-1.

13 **Q. Does that mean the company can “over-earn” simply by having the CUA in**
14 **effect?**

15 A. Yes, the proposed CUA has the potential to allow the company to collect more
16 revenues than would be deemed appropriate under traditional ratemaking principles.
17 Without a revenue cap a revenue cap or some other limitation, the proposed
18 mechanism does not consider total revenue or other productivity savings achieved
19 through operations. Revenue must be considered in the context of matched expenses,
20 rate base, and authorized rate of return to determine whether rates are set at just and

¹⁶ MDC C1 column (b) line21

¹⁷CAPD Exhibit MDC C1, Column (e), line 21

1 reasonable levels. The ATMOS CUA proposal undermines this ratemaking process
2 and substitutes an untested, unproven, and unfair proposal.

3 **Q. ATMOS has insisted that the financial health of the company is dependent upon**
4 **sustained volume levels to afford the recovery of authorized revenue**
5 **requirements. Is this sentiment correct?**

6 **A.** No. Assumptions such as the company must “sustain sales volume levels to achieve
7 its Allowed Rate of Return” suggests that volumes per customer must be sustained
8 to achieved the authorized rate of return. Such statements ignore the matching
9 principal. Throughout Ms. Childers’ as well as Mr. Smith’s comments, the element
10 of customer growth is consistently absent; that is, while incumbent customers may
11 become more energy efficient, new customer growth adds additional revenue which
12 offsets this conservation. Also note that Atmos recovers 62%¹⁸ of residential revenue
13 through non-volumetric charges. As previously discussed, **CAPD CUA Worksheet**
14 **Exhibit MDC C1-C7** demonstrates that customer growth overcomes the reduction
15 in use per customer for the projected 4 years in the worksheet. Further, the greater
16 Davidson - Metro counties are some of the fastest growing counties¹⁹ in the United
17 States since 2000; i.e., Rutherford 54%, Williamson 56% growth. This population
18 growth²⁰ which undoubtedly will yield new customers, is expected to continue within

¹⁸CAPD D.R. #1, Q97- response by Mr. Cagle.

¹⁹Table 6, Population for the 15 Largest Counties and Incorporated Places in Tennessee: 1990 and 2000, source: U.S. Census Bureau, Census 2000 (CAPD Exhibit MDC CC).

²⁰ Recent Tennessean Newspaper articles documenting customer growth in ATMOS service territory (CAPD Exhibit MDC Z).

1 the Company's service area. Factors such as customer growth, along with company
2 productivity and savings clearly demonstrate that the Company's assertion that the
3 CUA is needed to achieve its authorized return is erroneous.

4 **Q. What evidence does ATMOS provide regarding the need for a decoupling**
5 **mechanism to “to afford the Company a reasonable opportunity to achieve its**
6 **authorized revenue requirement.”?**

7 **A.** None. There is nothing within the Company's case which is new to regulators and the
8 natural gas industry. A trend of declining usage per customer has been around since
9 the 1980s.²¹ Mr. John Perkins (President of NASUCA) in his overhead presentation
10 to the NARUC Summer Meeting detailed how declining usage per customer has been
11 a national phenomenon since the 1980's, but customer growth has provided a
12 sustained increases in natural gas usage overall.²² In addition, the American Gas
13 Association has forecasted that the decline in usage per customer will shrink to 0.5%
14 by 2020 rather than increase.²³ If the trend in usage is subject to moderate in the
15 future from 1.5% to 0.5%, the isolated impact of this trend on the Company's future

²¹ CAPD Exhibit MDC-FF *American Gas Association - Energy Analysis: Forecasted Patterns in Residential Natural Gas Consumption*, EA 2004-04 and MDC-EE *American Gas Association - Energy Analysis: Patterns in Residential Natural Gas Consumption*, 1997-2001, EA 2003-01

²² CAPD Exhibit MDC P, p. 12 / Policy Options for Energy Efficiency Programs; Decoupling, Incentives & Third-Party Administrators, Naruc Summer Meeting, New York City, July 17, 2007, Data Source: Energy Information administration, US. Department of Energy

²³ CAPD Exhibit MDC-FF *American Gas Association - Energy Analysis: Forecasted Patterns in Residential Natural Gas Consumption*, EA 2004-04 and MDC-EE *American Gas Association - Energy Analysis: Patterns in Residential Natural Gas Consumption*, 1997-2001, EA 2003-01.

1 revenues would be minimized.

2 Companies such as ATMOS have been doing business for decades in the face of the
3 trend. Customer growth and other factors have historically assisted the company in
4 overcoming a 1.5% decline in the usage per customer. Indeed, between 1995-2005,
5 despite inflation and a decline in per customer usage, ATMOS remained profitable.

6 **Q. Without the benefit of a decoupling mechanism, what has been the Company's**
7 **historical Rate of Return (R.O.R.)?**

8 **A.** The company has historically demonstrated that an LDC does not need a decoupling
9 mechanism to remain profitable. Below is the R.O.R. Summary as detailed in Exhibit
10 CAPD -SB Schedule 7²⁴ in TRA Docket 05-00258 - attached as **(CAPD Exhibit**
11 **MDC R):**

	ROR:	ROE:
1997	9.17 %	11.8%
1998	11.37 %	18.3%
1999	7.42 %	8.2%
2000	9.35 %	9.7%
2001	10.29 %	20.7%
2002	9.46 %	20.3%
2003	9.04 %	18.2%
2004	10.02 %	14.2%

21 **Q. Mr. Smith has stated that even with a decoupling mechanism in operation, the**

²⁴Dr. Brown's Schedule 7 in 05-00258 from initial petition filing in this docket.

company still assumes the overall risks of doing business. Would the CUA reduce the amount of risk for the company?

A. Dr. Brown specifically addresses CUA and the concept of risk in his testimony. When the CUA is looked at within the context of the WNA and the inclusion of a gas cost portion of uncollectible cost, a CUA will further isolate ATMOS from risks that it once formerly shouldered. The burden on consumers will be greater.

Q. What other changes have made the company's decoupling proposal unnecessary?

A. Although ATMOS rates were cut some \$6 million in Docket 05-00258, the TRA allowed the company to increase its Residential Service Fee from \$6 per month to \$9 for Summer billing period and \$12 for the Winter billing period respectively. Thus, the TRA has already reduced the uncertainty in recovering fixed cost through volumetric rates.

THE DISINCENTIVE ISSUE:

Q. ATMOS states: “The proposed CUA will decouple the revenues from the volumes of gas consumed, and thus remove the disincentive the company currently has to encourage energy efficiency and conservation while at the same time stabilizing customers’ bills”²⁵. How does the Company prove it currently has a disincentive to promote conservation?

A. It does not attempt to prove it has a disincentive, rather it suggests in page 8 (lines 14-16) of Mr. Smith's testimony that "The proposed CUA will decouple the

²⁵Ibid p.6, lines 1-3.

1 collection of non-gas revenues from the volumes of gas consumer, and thus remove
2 the current disincentive to encourage energy efficiency and conservation.”

3 Other state commissions such as Iowa²⁶ and Connecticut²⁷ have questioned whether
4 there is a disincentive issue at all.

5 **Q. Is there any evidence that ATMOS' CUA decoupling proposal would lead to**
6 **increased energy efficiency investment by either the company or ratepayers?**

7 **A.** No. In concept, ATMOS proposed CUA will only make it indifferent regarding the
8 promotion of conservation and energy efficiency efforts. Conspicuously absent from
9 the Companies' testimony is any suggestion, let alone a specific proposal, that they
10 will invest more dollars²⁸ in energy efficiency programs if the CUA is approved.
11 Further, the company was asked in CAPD Data Request #1, Q. 104: What is the
12 estimated “savings” in terms of ccf billed per year to Tennessee customers who
13 participated in ATMOS' pilot program?

14 Company response: “The company has not performed any studies nor done any
15 specific analysis that would provide a definite answer to this question.” Some states
16 have required conservation program proposals of specific goals when decoupling is

²⁶ Iowas Utilities Board, in its order in Docket No. NOI-06-01 issued December 18, 2006, p. 3, paragraph 2 (CAPD Exhibit MDC I) “The data does not show a direct correlation between net operating income and declining customer usage as a result of energy efficiency programs to date.”

²⁷ Investigation into decoupling Energy Distribution Company Earnings from Sales, Decision, Connecticut Department of Public Utilities, Docket 05-05-09, January 18, 2006.

²⁸ ATMOS has committed \$80,000 (\$50,000 (Smith p. 15, line 16) +\$30,000 (agreement in Docket 07-00152)) developing an experimental unspecific, residential “pilot program”.

1 considered.²⁹ In any event, company sponsored conservation programs appear to have
2 little impact. Dr. Dismukes presented findings to the NASUCA Mid-Year Meeting in
3 June this year relating that the percent of gas saved in major conservation programs
4 amounted a range of 0.1% to 1% for the top ten gas utilities in 2004.³⁰

5 **Q. Is it your opinion that ATMOS could promote an energy conservation program**
6 **as it does in other states³¹, and can do so without the need for a change in**
7 **regulatory policy?**

8 A. Yes, ATMOS has proven that it has been able to withstand long periods without rate
9 increases thus indicating the nature of its fast growing service territory and the will
10 to promote productivity within the organization reflected in operating income.
11 Traditional regulatory policy always allows a company to file for additional revenue
12 when necessary as illustrated by the short amount of time between this rate filing and
13 the prior proceeding for ATMOS. Moreover, specific conservation initiatives and
14 proposals can be addressed during rate cases; however there are no such programs
15 proposed in this case.

16 **Q. Mr. Smith states on page 16 of his testimony that the CUA will not negate the**

²⁹ Washington Utilities And Transportation Commission, Docket UE-060266 and UG-060267, Order 8, p. 23, paragraph 655 (CAPD Exhibit MDC A).

³⁰ "Regulatory Issues for consumer Advocates in Rate Design, Incentive & Energy Efficiency" David E. Dismukes, Ph.D, NASUCA Mid-Year, June 11, 2007, p.13 (CAPD Exhibit MDC K)

³¹ In response to CAPD Data Request #1, Q.101 indicates that it has had conservation programs operating in Iowa since 1990, Kentucky since 2000, and a recent order in Missouri.

benefits of conservation measures taken by customers. Is this statement correct?

A. No. While most of a consumer's bill is for the cost of gas, a household also pays the volumetric charge portion for service as well. The fairness in a volumetric charge is that a consumer has some control over the utility bill. The more a consumer uses natural gas, the greater use he makes of the infrastructure of the utility company. Thus, consumers that use more natural gas pay more because they are placing greater demand on the infrastructure. A simple analogy is the state tax on gasoline in Tennessee from which the proceeds are applied to road building and maintenance. The more driving a tax-payer does in making use of the roads of this State, the more gasoline he has to purchase and pay tax upon. In doing so the tax-payer that drives and buys gas frequently is fairly paying more tax because he is putting more demand on the roads he uses. A tax-payer that does not drive as much and therefore does not place as much demand on the state's roads, consumes less gasoline and thus pays less taxes on gasoline.

Whether under the CUA or not, if a consumer sacrifices in the course of conserving natural gas, a household will be rewarded with a lower bill, both for the cost of the natural gas used and the cost of the service via the volumetric portion. But unlike traditional rate making, the CUA will recapture those savings for the company. After the true-up, the savings achieved by individual consumers will be undercut. Under the company's plan, it really doesn't matter if the individual customer used more or less than the "benchmark average", the customers will have an adjustment added to their

1 bill based on the average revenue per customer of all the customers in their rate class
2 compared with the “benchmark average”. Thus, the CUA offers no reward or
3 incentive to consumers to conserve.

4 **Q. Mr. Smith concludes his testimony on page 16 by suggesting (on lines 15 & 17):**
5 **“It will benefit ratepayers by adding stability to their annual energy bill.” Is**
6 **“stability” (of their annual energy bill) a perceived value by Tennessee**
7 **ratepayers?**

8 **A.** No. I fail to see how the CUA will grant any level of stability to the bills of
9 consumers.

10 **IV. (C) THE POLICY SHIFT**

11 **Q. Mr. Smith referenced groups “supporting this shift in policy towards**
12 **conservation and away from rate designs that encourage increased gas sales”**
13 **are you aware of any statements refuting the claims of “decoupling” for**
14 **consumers?**

15 **A.** There has been opposition to this proposed policy shift. Consumer Advocates of
16 many jurisdictions and the National Association of State Utility Consumer Advocates
17 (“NASUCA”) have studied decoupling and oppose it. At least ten (10) states have
18 rejected decoupling mechanism proposals³², including the TRA in this company’s last

³²Testimony of Dr. David Dismukes before the Public Service Commission of Utah in Docket No. 05-057-TO1, Attachment 2 - Overview of states where decoupling was rejected or withdrawn (CAPD Exhibit MDC Y).

1 rate case.³³ NASUCA first responded to the decoupling in a letter from John Perkins
2 (NASUCA President) (**CAPD Exhibit MDC N**), dated August 18, 2006, refusing
3 NASUCA endorsement.

4 Following the release of Mr. Perkins' letter, NASUCA members began discussing the
5 "decoupling issue". As Chair of the NASUCA Consumer Protection Committee, I
6 formed a subcommittee inviting interested NASUCA members within the Consumer
7 Protection, Gas, and Electric Committees to develop a resolution detailing
8 NASUCA's position regarding the Decoupling issue (**CAPD Exhibit MDC M**). The
9 development process lasted several months, and a final draft was proposed and
10 adopted at the NASUCA Mid-Year Conference in June of 2007.

11 The NASUCA resolution³⁴ provides a foundation for member offices to point out the
12 flaws with most decoupling proposals and urges legislators and regulators to refuse
13 such proposals in their states/jurisdictions.

14 **V. THE GTI PROPOSAL**

15 **Q. Do you have an opinion regarding the proposed GTI funding mechanisms?**

16 A. Yes. I do not see the need for ATMOS consumers to fund this particular proposal
17 for several reasons. GTI has ample financial means³⁵.

18 I would disagree with any suggestion that there is no demand in the public

³³ Arizona, Arkansas, Connecticut, Florida, Iowa, New Mexico, Tennessee and Washington (not an all inclusive list).

³⁴ MDC M

³⁵ According to the organization's annual report for 2006 posted on GTI's website, GTI has net assets of \$91.5 million.

1 marketplace for energy efficient products. Demand naturally suggests the competitive
2 market itself will supply research and development in this area. The company has
3 noted the decline in usage per customer and attributed that decline to improved
4 efficiency and conservation. With the recent gas price volatility, it appears that
5 consumers are eagerly engaging in a market for energy efficient products and
6 practices, not just products alone. I would also disagree at this time that the benefits
7 provided by a GTI project will outweigh the funds supplied by consumers.

8 Also, several of the specific GTI project proposals appear to be focused solely on
9 making the company's operations more efficient. While the Consumer Advocate
10 supports the company's efforts in this regard, it is the company that gains a benefit in
11 becoming more efficient as any savings created will lead to more benefits for
12 stockholders during the interludes between rate cases, benefits achieved solely by the
13 funds of consumers. Mr. Edelstein's testimony indicates that the Company will have
14 the discretion to pick and choose what programs are funded. Given that the
15 stockholders will have the discretion to select research projects and that stockholders
16 will likely benefit from efficiencies in operations, it would appear consumers are doing
17 all the funding without reaping the "benefits".

18 **Q. Is GTI the only research and development organization for natural gas?**

19 A. GTI has admitted that there are several other organizations that perform natural gas
20 research and development.³⁶

³⁶ See TRA Docket 04-00034, GTI's Response to Chattanooga Gas Company's Data Requests, Response to Data Request #2 (May 5, 2004).

1 **Q.** **Does that complete your testimony?**

2 **A.** Yes

3

4

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6

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9

10

END

110126

BEFORE THE TENNESSEE REGULATORY AUTHORITY
AT NASHVILLE, TENNESSEE

IN RE: PETITION OF ATMOS ENERGY CORPORATION FOR APPROVAL OF A
GENERAL RATE INCREASE

DOCKET NO. 07-00105

AFFIDAVIT

I, Michael D. Chrysler, Regulatory Analyst, for the Consumer Advocate Division of the Attorney General's Office, hereby certify that the attached Direct Testimony represents my opinion in the above-referenced case and the opinion of the Consumer Advocate Division.

Michael D. Chrysler
MICHAEL D. CHRYSLER

Sworn to and subscribed before me
this 21st day of August, 2007.

Emily Knight
NOTARY PUBLIC



My commission expires: Sept. 20, 2007

2007

Before the

TENNESSEE REGULATORY AUTHORITY

**IN RE: PETITION OF ATMOS ENERGY CORPORATION FOR APPROVAL OF A
GENERAL RATE INCREASE**

DOCKET NO. 07-00105

**EXHIBITS
OF
MICHAEL D. CHRYSLER**

August 21, 2007

Summary of Exhibits
Michael D. Chrysler
Consumer Advocate Division

TRA Docket 07-00105

CAPD Exhibit Number	Commission Jurisdiction	Filing	EXHIBIT DETAIL
MDC A	Washington	Commisison Order	Washington State Utilities And Transportation Commission, Order in UE-060266 and UG-060267, Order 08 rejecting Tariff Sheets; Authorizing And Rquiring Compliance Filing
MDC B	Washington	Public Counsel Opening Brief	Washington Utilities And Transportation Commision, Opening Brief of Public Counsel, in UE-060266 and UG-060267, dated October 31, 2006
MDC C1	Tennessee	Summary of Projected Decoupling Revenue	Summary Detail of Decoupling Revenue By Revenue Class
MDC C2	Tennessee	Summary of Residential CUA Revenue	Calculation Sheet of Residential CUA Revenue
MDC C3	Tennessee	Developme nt Summary	Development of Projected Billing Increments based on Customer Growth and Reduction in Usage Factors - Residential
MDC C4	Tennessee	Summary of Commercial CUA Revenue	Calculation Sheet of Commercial CUA Revenue
MDC C5	Tennessee	Developme nt Summary	Development of Projected Billing Increments based on Customer Growth and Reduction in Usage Factors - Commercial
MDC C6	Tennessee	Summary of Commercial CUA Revenue	Calculation Sheet of Public Authority CUA Revenue
MDC C7	Tennessee	Developme nt Summary Base	Development of Projected Billing Increments based on Customer Growth and Reduction in Usage Factors - Public Authority
MDC C8	Tennessee	Document For Revenue Projection ATMOS Proposed	ATMOS ENERGY Corporation - Projected Revenue Exhibit - PJC-1 in TRA Docket 07-00105
MDC C9	Tennessee	CUA Tariff Sheet	ATMOS Tariff sheet Original 51.1 CUA Rider
MDC D1	Tennessee	Settlement Agreement Formal	Alleged Violations of Tenn. Code Ann. Sectin 65-4-120 92004) And Rules of the Tennessee Regulatory Authority Chapters 1220-4-5-.08 and 1220-4-5-.09 by: Atmos Energy Corporation
MDC D2	Tennessee	Notice of Violations	ATMOS Energy Corporation - Murfreesboro Incident, August 2, 2005 in TRA Docket 05-00323
MDC D3	Tennessee	Order Approving Civil Penalty Stipulation	TRA Order In RE: ATMOS energy Corporation - Incident 8/02/05, Order Approving Proposed Civil Penalty and Accepting Response Offering Long Term Corrective Actions
MDC D4	Tennessee	Agreement Profitability	Alleged Violation by Atmos Energy corporation of Stipulations Adopted in Docket No. 5-00281, Docket No. 07-00152
MDC D5		Model Rev.	ATMOS Economic Analysis - ATMOS Macro
MDC D6	Tennessee	Deficinecy Calculation	Reference Exhibit - Traditional Ratemaking Analysis
MDC E	Michigan	Testimony	Testimony of David E. Dismukes, Ph.D. MPSC Case No U-14893

Summary of Exhibits
Michael D. Chrysler
Consumer Advocate Division

TRA Docket 07-00105

CAPD Exhibit Number	Commission Jurisdiction	Filing	EXHIBIT DETAIL
MDC F	Washington	Testimony	Direct Testimony of Michael L. Brosch On Behalf of Public Counsel, July 19, 2006 (Non-Confidential)
MDC F1	Washington	Testimony	Cross-Answering Testimony of Michael L. Brosch, Before The Washington Utilities & Transportation Commission, UE-060266 and UG-060267, dated August 23, 2006
MDC G	New Mexico	Commisison Order	Final Order Partially Adopting Recommended Decision, In the Matter of the Petition By Public Service Company of New Mexico For A Revision of its Rates, Rules and Charges Pursuant to Advice Notice Nos. 755 and 756, in Case No. 06-00210-UT, dated June 29, 2007
MDC G1	New Mexico	Hearing Officer Recommen ded Decision	Recommended Decision Of The Hearing Examiner in New Miexico Public Regulation Commission Case No. 06-00210-UT, In The Matter of the Application of Public Service company of New Mexico For a Revision To its Rates, Rules, and Charges Pursuant to Advice Notice No. 755 and 756 Pre-Filed Direct Testimony of William L Glahn (Public Version) On Behalf of Public Advocate, In the Matter of Aquila, Inc. DbA Aquila Networks ("Aquila"), Omaha, seeking individual general rate ncreases for Aquila's Rate Area One, Rate Area Two and Rate Area Three, Nebraska Public Service Commission Docket No. NG-0041, date March 16, 2007
MDC H	Nebraska	Testimony	State of Iowa Department of Commerce Utilities Board, Inquiry Into The Effect of reduced Usage On Rate-Regulated Natural gas Utilities, Docket No. NOI-06-1, Issued December 18, 2006
MDC I	IOWA	Commisison Order	Decoupling Rate Tracking for Declining Sales, A Piecemeal Approach, Mike Brosch, NASUCA Mid-Year Conference, June 11, 2007, Penel Discussion
MDC J	NASUCA	Overhead Presentatio n	Regulatory Issues for consumer Advocates in Rate Design, Incentives & Energy Efficiency, Dr. David Dismukes, NASUCA Mid-Year Meeting, June 11, 2007, Panel Discussion
MDC K	NASUCA	Overhead Presentatio n	In the Matter of Atmos Energy corporation's Tariff Provision Designed to Consolidate Rate and Implement a General Rate Increase for Natural Gas Service in the Missouri Service Area of Atmos. Case No. GR-2006-0387, Issued February 22, 2007, Effective March 4, 2007
MDC L	Missouri	Commisison Order	NASUCA Resolution 2007-01 "NASUCA Energy Conservation And Decoupling Resolution" approved June 12, 2007
MDC M	NASUCA	Resolution	Letter dated August 18, 2006 from NASUCA President John R. Perkins to Ms. Diane Munns and Mr. James E. Rogers, Re: National action Plan for Energy Efficiency
MDC N	NASUCA	Letter	Press Release and White Paper against decoupling
MDC O	ELCON	Paper Overhead Presentatio n	Presentation by NASUCA Presient John R. Perkins at the NARUC Summer Meeting, New York City July 17, 2007
MDC P	NASUCA	Presentatio n	Schedule 7 by Dr. Steve Brown "Atmos/United Consolidated Capital Sturcture, and Returns in Tennessee in TRA Docket 05-00258
MDC R	Tennessee		Nebraska Comission Order in Application No. NG-0041, Entered July 24, 2007 In the Matter of Aquila, Inc. d/b/a Aquila Networks (Aquila), Omaha, seeking individual rate increases for Aquila's Rate Area One, Rate Area Two, and rate Area three
MDC S	Nebraska	Commisison Order	ATMOS Energy Corporation - Current Main Extension Policy, Tariff Sheet Dated Octobe 4, 2002, Tariff sheets 62-66
MDC T1	Tennessee	Tariff Sheet'	ATMOS Energy Corporation - Proposed Main Extension Policy, Tariff Sheets 62, 63
MDC T2	Tennessee	Tariff Sheet	Direct Testimony of Michael L. Brosch, On Behalf of The People of the State of Illinois, The City of Chicago and The Citizens Utility Board, July 3, 2007, In jDocket No. 07-0241 and 07-0242
MDC U	Illinois	Testimony	Decoupling: Should Ratepayers Be Worried? Simon fitch, Public Counsel Washington State Attorney General's Office, Presentation to NARUC Summer Committee Meetings, SanFrancisco, California, August 2, 2006
MDC V	Washington	Overhead Presentatio n	

Summary of Exhibits
Michael D. Chrysler
Consumer Advocate Division

TRA Docket 07-00105

CAPD Exhibit Number	Commission Jurisdiction	Filing	EXHIBIT DETAIL
MDC W	Michigan	Testimony	Direct Testimony and Exhibits of Dr. David E. Dismukes, on Behalf of the Michigan Attorney General, dated November 13, 2006 in MPSC Case No. U-14893
MDC X	Arizona	Commisison Order	Re: Southwest Gas Corporation, Docket No. G-01551A-04-0876, Decision No. 68487, Arizona Corporation Commission, February 23, 2006
MDC Y	Utah	Testimony	Direct Testimony and Exhibits of Dr. David E. Dismukes, on Behalf of the Utah Committee of Consumer Services, filed June 1, 2007 in Docket Number 05-057-T01
MDC Y1	UTAH	Exhibits	Exhibits in Support of Direct Testimony of Dr. David E. Dismukes, docket Number 05-057-TO1
MDC Z	Tennessee	Exhibit	Newspaper articles documenting Mid-State
MDC AA	AGA Textbook	Gas Rate Fundament als	American Gas Association, Gas Rate Fundamentals, Third Edition
MDC BB		NARUC Rate School	30th Annual Eastern Utility Rate School, October 27- November 1, 2002, Section 7, "Choosing the Test Year, Gail P. Brady, p. 6
MDC CC		Census Bureau Data	Census Bureau, State of Tennessee 1990 - 2000, Cities, Counties
MDC DD	North Carolina	Commission Order	North Carolina Docket No. G-9, Sub 528 Order On Annual Review of Gas Costs
MDC EE	AGA		American Gas Association, Patterns In Residential Natural Gas Consumption, 1997 - 2001, dated June 16, 2003
MDC FF	AGA		American Gas Association, Forecasted Patterns In Residential Natural Gas Consumption, 2001-2020

**BEFORE THE WASHINGTON STATE
UTILITIES AND TRANSPORTATION COMMISSION**

WASHINGTON UTILITIES AND	)	
TRANSPORTATION COMMISSION,	)	DOCKETS UE-060266 and
	)	UG-060267 (<i>consolidated</i>)
Complainant,	)	
v.	)	ORDER 08
	)	
PUGET SOUND ENERGY, INC.,	)	REJECTING TARIFF SHEETS;
	)	AUTHORIZING AND REQUIRING
Respondent.	)	COMPLIANCE FILING
.....	)	

Synopsis: *The Commission rejects revised tariff sheets Puget Sound Energy, Inc. (PSE or the Company), filed on February 15, 2006, but authorizes and requires the Company to file tariff sheets that will result in increases of about 1.0 percent for electric rates and 3.2 percent for natural gas rates, which are found on the record of this proceeding to be fair, just, reasonable and sufficient. The Commission rejects PSE's, and others' proposals to implement novel mechanisms that would shift disproportional risks to customers. The record does not demonstrate that such programs are necessary for the Company, beneficial for customers, or in the public interest. The Commission approves a pilot, incentive-based program to promote electric conservation and increased funding for low-income assistance programs.*

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SUMMARY

- 1 **PROCEEDINGS:** On February 15, 2006, Puget Sound Energy, Inc. (PSE), filed revisions to its electric tariff as required by the Commission's Order 04 in Docket UE-050870, the Company's 2005 PCORC (power cost only rate case).¹ PSE also filed revisions to its natural gas tariff. The revisions proposed a general rate increase of \$148.8 million, or 9.21 percent for electric service and \$51.3 million, or 5.34 percent for gas service. The Commission suspended the proposed tariff revisions on February 18, 2006, prior to their stated effective date of March 18, 2006.
- 2 PSE adjusted its request via supplemental testimony filed on July 7, 2006, taking into account the Company's updated base power costs approved in Docket UE-060783, a periodic Power Cost Adjustment (PCA) proceeding, and other factors. The Company based its revised proposal on an asserted electric revenue deficiency of \$42.9 million and an asserted natural gas revenue deficiency of \$39.2 million.
- 3 On July 19, 2006, Staff, Public Counsel and the intervening parties filed their respective response testimonies. Staff opposed the Company's request for increased revenue and, based on its responses concerning cost of capital and other matters, recommended a \$40.7 million reduction from currently approved annual electricity revenue and a \$19.3 million increase in annual natural gas revenue. Public Counsel, ICNU and other parties sponsored various ratemaking adjustments and presented evidence on several policy matters. Staff, however, is the only party opposing PSE that presented a full revenue requirement recommendation.
- 4 On rebuttal, filed August 23, 2006, PSE further reduced its asserted electric revenue deficiency to \$33.8 million (1.97 percent) and its request for added natural gas revenue to \$39.0 million (4.06 percent), taking into account certain adjustments proposed by others in their response cases and agreed to by the Company. On September 15, 2006, PSE and Staff stipulated to a number of revenue requirement adjustments. As a result, the Company again adjusted its request for additional revenue down to \$33.5 million for electric and \$38.9 million

¹ A glossary of acronyms and terms is attached for the convenience of readers.

for natural gas. Staff adjusted its recommended electric revenue decrease to (\$31.9) million and adjusted its recommended natural gas revenue increase to \$20.5 million. Table 1 summarizes the final levels of adjustment to annual revenue proposed by the two parties who put on full revenue requirement cases.

TABLE 1
Proposed Total Adjustments to Annual Base Rates
Revenue Requirement (\$M) Relative to Current Rates²

	As-Filed³	Supplemental	Response	Rebuttal	Stipulation
Electric:					
PSE	\$140.9	\$42.9		\$33.8	\$33.5
Staff			(\$41.0)		(\$31.9)
Natural Gas:					
PSE	\$40.4	\$39.2		\$39.0	\$38.9
Staff			\$19.6		\$20.5

- 5 The Commission, having suspended the tariff filing by order entered on February 22, 2006, conducted a public comment hearing in Renton, Washington on June 29, 2006, and evidentiary hearings in Olympia, Washington, on September 18 - 21 and 25, 2006. The parties filed Initial Briefs on October 31, 2006, and Reply Briefs on November 14, 2006. This order resolves all remaining contested issues.
- 6 **PARTY REPRESENTATIVES:** Kirstin S. Dodge, Sheree S. Carson and Jason Kuzma, Perkins Coie, Bellevue, Washington, represent PSE. Simon ffitich, Assistant Attorney General, Seattle, Washington, represents the Public Counsel Section of the Washington Office of Attorney General (Public Counsel). Robert D. Cedarbaum, Senior Assistant Attorney General, Olympia, Washington, represents the Commission's regulatory staff (Commission Staff or Staff).⁴

² Excludes any adjustment related to proposals for post-test year additions to rate base suggested as alternatives to PSE's proposed depreciation tracker mechanism.

³ According to PSE's cover letter transmitting the Company's initial filing on February 15, 2006, the electric revenue request was \$148.8 million and the gas revenue request was \$51.3. See also Exhibit 171 (Harris Direct) at 6:11-12. The lower figures in this column are taken from Exhibit 421 (Story Direct) at 2:7-9, Exhibit 431 (Story Supplemental) at 2:3-6, Exhibit 222 (Karzmar Direct) at 2:3-5 and Exhibit 228 (Karzmar Supplemental) at 1:15-17.

⁴ In formal proceedings, such as this case, the Commission's regulatory staff functions as an independent party with the same rights, privileges, and responsibilities as any other party to the proceeding. There is an "ex parte wall" separating the Commissioners, the presiding ALJ, and the Commissioners' policy and accounting advisors from all parties, including Staff. RCW 34.05.455.

- 7 S. Bradley Van Cleve, Matthew W. Perkins, and Irion Sanger, Davison Van Cleve, Portland, Oregon, represent the Industrial Customers of Northwest Utilities (ICNU). Michael L. Kurtz and Kurt J. Boehm, Boehm, Kurtz & Lowry, Cincinnati, Ohio, represent the Kroger Co., on behalf of its Fred Meyer Stores and Quality Food Centers divisions (Kroger). Elaine L. Spencer, Graham & Dunn PC, Seattle, Washington, represents Seattle Steam Company (Seattle Steam). Norman Furuta and Rita Liotta, Department of the Navy, Daly City, California, represent the Federal Executive Agencies (FEA). Michael Alcantar and Donald Brookhyser, Alcantar & Kahl LLP, Portland, Oregon, represent the Cogeneration Coalition. Edward A. Finklea and Chad M. Stokes, Cable Huston Benedict Haagensen & Lloyd LLP, Portland, Oregon, represent Northwest Industrial Gas Users (NWIGU). Nancy Glaser, NW Energy Coalition (NVEC), represents the NVEC. John O'Rourke, Director, Citizens' Utility Alliance (CUA), represents the CUA. Ronald L. Roseman, Attorney, Seattle, Washington, represents the Energy Project.
- 8 **COMMISSION DETERMINATIONS:** The Commission suspended and set for hearing the rates PSE initially proposed. The Company, as summarized above, revised its as-filed proposal downward on several occasions during the pendency of these proceedings. Accordingly, the Commission has no record upon which to determine, and does not need to determine whether the Company's as-filed rates meet the statutory fair, just, reasonable and sufficient standard for approval. Rather, we must determine such rates on the basis of the record before us.⁵ In this order, we evaluate PSE's final revised rate request and resolve a number of contested issues that separate the parties by more than \$80 million. We also resolve several important policy issues related to risk mitigation and other matters. We summarize our determinations in Table 2.

⁵ RCW 80.28.020.

TABLE 2
Summary of Commission Determinations

REVENUE REQUIREMENT ISSUES				Commission Determination																												
	Power Costs:																															
		Should gas costs be updated and AURORA rerun?		YES																												
		Should PSE be required to use forward market electric prices to determine power costs?		NO																												
		Should combustion turbine run times be increased and down times decreased relative to PSE AURORA model run inputs?		NO																												
		Should hydro-shaping be adjusted to increase peak hydro relative to PSE AURORA model run inputs?		NO																												
	Director and Officer Insurance: Should PSE’s proposed allocation of premiums be rejected in favor of Staff’s proposal?			NO																												
	Rate of Return:			Embedded Table Below																												
	<table><tr><th>Component</th><th>Share (%)</th><th>Cost (%)</th><th>Weighted Cost</th></tr><tr><td>Equity</td><td>44.13</td><td>10.4</td><td>4.59</td></tr><tr><td>Long-term debt</td><td>48.01</td><td>6.64</td><td>3.19</td></tr><tr><td>Short-term debt</td><td>2.60</td><td>6.66</td><td>0.17</td></tr><tr><td>Trust Preferred</td><td>5.22</td><td>8.54</td><td>0.45</td></tr><tr><td>Preferred</td><td>.04</td><td>7.61</td><td>0.00</td></tr><tr><td>Overall Rate of Return</td><td></td><td></td><td>8.40</td></tr></table>				Component	Share (%)	Cost (%)	Weighted Cost	Equity	44.13	10.4	4.59	Long-term debt	48.01	6.64	3.19	Short-term debt	2.60	6.66	0.17	Trust Preferred	5.22	8.54	0.45	Preferred	.04	7.61	0.00	Overall Rate of Return			8.40
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RATE SPREAD / RATE DESIGN				Commission Determination																												
	Electric: Should the Commission approve and adopt the parties’ stipulation?			YES																												
	Gas:																															
		What rate spread should the Commission approve?		PSE																												
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Policy Issues		Commission Determination
Proposed PCA Modifications Should the Commission:		
	Modify deadband and/or sharing bands?	NO
	Eliminate Exhibit E requirements for treatment of power costs under certain contracts?	YES
	Eliminate paragraph 10 general rate case filing requirement?	NO
	Allow new hedging line of credit costs?	YES
Depreciation: Should the Commission:		
	Approve a depreciation tracker mechanism as proposed by PSE?	NO
	Approve post-test period additions to rate base?	NO
Decoupling:		
	Should the Commission approve a decoupling mechanism for natural gas rates?	NO
Electric Conservation Incentive/Penalty:		
	Should the Commission approve an incentive/penalty mechanism?	YES, adopt Staff proposal for a 3-year pilot program

- 9 We determine that PSE should be authorized and required to file rates in compliance with our decisions, as summarized here and discussed in detail below. When implemented via the compliance filing we require the Company to make, the resulting rates will be fair, just, reasonable and sufficient, and neither unduly discriminatory nor preferential. Because we require PSE to rerun its AURORA power cost model based on updated natural gas costs, we will determine the exact revenue deficiency for electric service during the compliance phase.⁶ We find a revenue deficiency of \$31,259,011 for natural gas and authorize PSE to file rates to recover additional revenue in this amount.

⁶ As discussed below, we require PSE to rerun the AURORA model using gas prices updated through November 30, 2006. As a point of reference, using gas prices based on forward prices for the three months ended September 30, 2006, the power cost adjustment in PSE's results of operations would be \$293,563,457 (*i.e.*, NOI of (\$182,224,643)). Using this as a point of reference for illustrative purposes and taking into account all other adjustments, PSE's total revenue requirement deficiency for electric would be (\$2,102,237). The final revenue requirement for electric that PSE will use in making its compliance filing will be either slightly higher or lower depending on the level of power costs determined via the required rerun of AURORA. *See infra*, Table 9.

MEMORANDUM

I. Background and Procedural History

- 10 On February 15, 2006, PSE filed revisions to its currently effective Tariff WN U-60, Tariff G, Electric Service, and revisions to its currently effective Tariff WN U-2, Gas Service. The proposed tariff revisions bore an effective date of March 18, 2006. PSE proposed a general rate increase of 9.21 percent for the electric tariffs and 5.23 percent for the gas tariffs. The Commission suspended the proposed tariff revisions on February 22, 2006, consolidated the two dockets, and set the matters for hearing.
- 11 The Commission conducted a prehearing conference on March 21, 2006, before Administrative Law Judge C. Robert Wallis. On March 23, 2006, the Commission entered Order 02, granting various pending petitions to intervene, authorizing formal discovery, and establishing a procedural schedule. Administrative Law Judge Dennis J. Moss assumed responsibility as presiding officer in this proceeding during June 2006.
- 12 The parties prefiled extensive testimony and numerous exhibits sponsored by 35 witnesses, including 21 for PSE, 2 for Public Counsel, 4 for Staff and 8 for various intervenors. On July 25, 2006, Staff filed a proposed Rate Spread and Rate Design Settlement for electric rates. All parties whose prefiled testimony addressed these subjects supported the proposal and no party voiced opposition.
- 13 On September 15, 2006, Staff and PSE filed their Agreement on Revenue Requirement Adjustments. In making this filing, Staff noted that no other party had filed testimony on the issues to which Staff and PSE reached agreement.
- 14 The Commission held a public comment hearing in Renton, Washington during the evening of June 29, 2006, and conducted evidentiary hearings in Olympia, Washington on September 18-21 and 25, 2006. Chairman Mark H. Sidran, Commissioner Patrick J. Oshie and Commissioner Philip B. Jones were assisted at the bench by presiding Administrative Law Judge Dennis J. Moss. Altogether, the record includes more than five hundred exhibits entered during five days of evidentiary proceedings. The transcript of these proceedings is nearly 1,000 pages in length.

- 15 The parties filed Initial Briefs on October 31, 2006, and Reply Briefs on November 14, 2006. The Commission here enters its Final Order resolving the disputed issues, approving certain uncontested adjustments, and granting appropriate relief considering the full record of proceedings and the parties' arguments based on that record.

II. Discussion and Decisions

A. Risk Mitigation Proposals—Electric

1. Modification of Power Cost Adjustment Mechanism

- 16 The Commission authorized PSE to implement a power cost adjustment (PCA) mechanism during 2002 as part of a comprehensive settlement of the Company's general rate proceeding in Docket Nos. UE-011570 and UG-011571.⁷ PSE now requests us to authorize four changes to the PCA mechanism, as follows:

- Eliminate the current \$20 million dead band, consolidate the remaining bands, and modify the cost-sharing percentages in each band.
- Eliminate paragraph 10 of the PCA, which requires PSE to file a general rate case within three months after the conclusion of a power cost only rate case (PCORC)⁸ that results in an increase to general rates.
- Eliminate Exhibit E to the PCA, which provides for asymmetrical treatment of costs associated with certain long-term power contracts and purchased power agreements for hydroelectric resources.
- Add to the Power Cost Baseline Rate the cost associated with a new line of credit to support wholesale power hedging transactions.

⁷ *WUTC v. Puget Sound Energy, Inc.*, Docket Nos. UE-011570 & UG-011571, Twelfth Supp. Order (2002).

⁸ The PCORC mechanism allows for expedited consideration between general rate proceedings of the prudence and rate treatment of costs associated with major generation acquisitions by PSE. The PCORC mechanism was also approved as part of the settlement in Docket Nos. UE-011570 & UG-011571.

We discuss below our reasons for denying PSE's first two requests and granting the second two.

a. Eliminate the current \$20 million dead band, consolidate the remaining bands, and modify the cost-sharing percentages in each band.

- 17 The PCA currently includes a \$20 million dead band within which PSE either absorbs all power costs that exceed the Power Cost Baseline Rate or retains all savings if power costs fall below the baseline. PSE shareholders and ratepayers share excess costs or savings greater than \$20 million, as shown in Table 3. PSE proposes in this proceeding the PCA cost sharing bands shown in Table 4.

TABLE 3

Current PCA Sharing Bands

Power Costs (\$ in millions) (over or under the PCA baseline)	Customers' Share	Shareholders' Share
\$0 - \$20 +/-	0%	100%
\$20 - \$40 +/-	50%	50%
\$40 - \$120 +/-	90%	10%
> \$120 +/-	95%	5%

TABLE 4

Proposed PCA Sharing Bands

Power Costs (\$ in millions) (over or under the PCA baseline)	Customers' Share	Shareholders' Share
\$0 - \$25 +/-	50%	50%
\$25 - \$120 +/-	90%	10%
> \$120 +/-	95%	5%

PSE argues the current PCA mechanism exposes the Company to a significant amount of uncontrollable hydro risks—in two years out of three, hydro variability would increase or decrease power costs by up to \$25 million, according to PSE.⁹

⁹ PSE Initial Brief ¶25 (citing Aladin, Exhibit 11C at 20:3-15).

The Company argues that such variations cannot be controlled regardless of how well PSE manages its electric portfolio overall.¹⁰

- 18 Although hydro risk is indeed variable, the current PCA adequately addresses this risk by providing for deferral and amortization of excess power costs associated with hydro variations.¹¹ Moreover, we expect hydro variability will be reasonably balanced over time. While below normal hydro may result in excess power costs in some years, this will be offset during other periods when hydro is more abundant.
- 19 Again focusing on the subject of risk sharing, PSE argues that the expiration earlier this year of a \$40 million cumulative cap on the Company's power cost exposure under the PCA will result in "a huge amount of extreme power cost risk...shifted onto PSE going forward, unless the Commission approves modification of the PCA Mechanism in this case."¹² This argument depends on a distorted perspective on the relationship of the various components of the PCA. The Commission approved in 2002 the balance of risks inherent in the dead band and the sharing bands, and also approved the \$40 million cap as a means to temporarily mitigate risk to the Company so that it could improve its financial condition over a period of years. That is, the fundamental balance of risks under the PCA was temporarily tilted in PSE's favor by the \$40 million cumulative cap considering the Company's distressed financial circumstances in the wake of the western energy crisis. Expiration of the cumulative cap was a feature of the PCA mechanism from the outset and cannot now be claimed to result in an unanticipated shift of risks to the Company. Instead, its expiration allows the balance of risk the Commission approved in 2002 to come fully into play for the first time.
- 20 PSE's proposal in this proceeding, by contrast, would result in a substantial transfer of risk from PSE to ratepayers without a corresponding ratepayer benefit. A central purpose of the PCA the Commission approved for PSE, and similar mechanisms approved or considered for other companies, is to protect the companies against extreme variations in power costs caused by such factors as the extraordinary market events that occurred during 2001 and 2002, serious drought,

¹⁰ *Id.*

¹¹ Exhibit 599 at 23:20 – 24:5 (Joint PCA).

¹² PSE Initial Brief ¶30.

or other circumstances that are beyond the companies' ability to foresee and control. PSE, in its proposal, seeks to modify the mechanism to share with customers the risk of normal variations in hydropower. This would mark a new and much expanded role for the PCA. We do not find such an expanded purpose to be in the public interest.

- 21 Finally, we observe that a PCA designed to insulate the Company from fifty percent of the cost risk of normal variations in hydro should necessarily be accompanied by an adjustment to the return on equity. The record in this proceeding does not include substantial competent evidence upon which we might determine the magnitude of the adjustment to return on equity that would be required to account for such a reduction in risk.
- 22 Before leaving this topic, we address briefly PSE's argument that elimination of the dead band and a 50/50 sharing of the first \$25 million of power costs variation will align each party's interest to set the Power Cost Baseline Rate as close as possible to the level that is likely to be actually experienced during the rate year.¹³ We do not find such an incentive necessary. The Commission has reset the Power Cost Baseline Rate on several occasions and each time it has done so on the basis of a fully developed record. The Commission's goal has been to set the baseline as close as practicable to what is likely to be experienced during the rate year. We expect that practice to continue and we also expect the parties to continue to refine the method and improve the data upon which we act.
- 23 We find PSE has not carried its burden to show its proposed modifications to the PCA dead band and sharing mechanism are in the public interest and therefore do not approve the Company's request.

b. Remove the rate case requirement in Paragraph 10.

- 24 PSE would eliminate paragraph 10 of the PCA Mechanism, which requires the Company to file a general rate case within three months of the conclusion of a PCORC that results in an increase to general rates.¹⁴ On brief, the Company

¹³ PSE Initial Brief ¶27.

¹⁴ Paragraph 10 of the PCA provides:

Further, if at any time after July 1, 2005 the Company shall file for a Power Cost Only review, and such filing shall result in an increase to general rates then in effect, the

asserts that given its history of two general rate cases and two PCORCs since 2002, this provision is not necessary and would result in inefficient ratemaking. PSE offers no explanation of how this “history” makes the provision unnecessary or how the requirement leads to “inefficient ratemaking.”

- 25 PSE also argues that no party objected to the proposed revision.¹⁵ That is not surprising given that the Company’s Initial Brief appears to be the first reference in the record to the proposed elimination of this paragraph. Thus, the Joint Parties did not address this issue on brief.¹⁶ However, on reply, the Joint Parties argue that this change should be denied on two grounds. First, they assert an absence of supporting evidence noting that PSE, as the party with the burden of proof has a duty to clearly identify and support its proposals in its testimony. In this instance, it failed to do so.
- 26 Second, the Joint Parties state that this paragraph provides an important safeguard to ensure an earnings review and a true-up of all costs after the occurrence of a PCORC—a single issue ratemaking mechanism.¹⁷
- 27 PSE has not supported its assertion that ratemaking efficiency will suffer if we do not approve elimination of paragraph 10 from the PCA mechanism. We reject the Company’s proposal to eliminate paragraph 10. PSE is free to seek a waiver of the provision under circumstances the Company believes will improve ratemaking efficiency. An important consideration that would inform the Commission’s decision to grant such a waiver would be whether there has been a very recent general rate proceeding.

c. PCA Exhibit E.

- 28 Exhibit E to the Company’s PCA lists certain long-term contracts for power purchases from Qualifying Facilities such as March Point and Sumas. The Commission has already approved these contracts as prudent. The cost of each

Company shall, within three (3) months of the effective date of any rate increase resulting from such Power Cost Only review, file a general rate case. Not more than one general rate case filing in any 12 month period shall be required to comply with this requirement.

¹⁵ PSE Initial Brief ¶13 (citing Exhibit 428C, which sets forth the Company’s proposed revisions to the PCA Mechanism). The exhibit does not, however, include a proposal to eliminate paragraph 10.

¹⁶ Public Counsel Reply Brief ¶98.

¹⁷ *Id.* ¶¶30-32.

contract at any given time is determined during the most recent general rate case or PCORC and is included in the power cost baseline. Under the existing PCA mechanism, if actual contract costs are higher than the Exhibit E contract rate, the difference is not included in the PCA true-up. However, if actual costs are lower than the contract rate, the lower costs are reflected in the PCA true-up.¹⁸ PSE, having agreed to this provision when the parties negotiated the PCA's terms in 2002, now argues this asymmetrical treatment is inequitable. PSE argues Exhibit E should be eliminated or modified to use the actual contract rates rather than the lower of the actual contract rate or the approved forecast rate.

- 29 The Joint Parties and FEA oppose eliminating Exhibit E. They assert Exhibit E was part of the original PCA's carefully balanced compromise. According to the Joint Parties, the rationale for including Exhibit E in the PCA stipulation was to "...hold some costs constant that the parties know are likely to rise (such as power supply contracts), precisely because there are other costs not tracked that parties know are likely to decline. "Examples of the latter are depreciation on Colstrip and transmission plant, which tend to decrease relative to revenues in between rate cases.... Holding these items constant tends to offset the power contract costs that may tend to rise."¹⁹ In essence, they argue because some costs that decline are not tracked in the PCA, PSE's contract cost recovery was capped by Exhibit E, ostensibly in return for allowing other power costs to rise between rate cases.²⁰
- 30 PSE disputes the Joint Parties' contention that holding return constant was a quid pro quo for the asymmetrical treatment of these costs, stating: "The lack of rate base adjustment in the PCA Mechanism for depreciating resources is counterbalanced by other benefits provided to customers under the PCA, such as foregone revenue growth on production plant and regulatory assets."²¹
- 31 The Joint Parties argument that Exhibit E should be retained because it was part of a grand compromise²² does little to support the notion that it remains good public policy five years later. We find unpersuasive the Joint Parties' argument that

¹⁸ Exhibit 439 (Story rebuttal) at 24:15-17.

¹⁹ Public Counsel Reply Brief ¶36.

²⁰ Public Counsel Initial Brief ¶114.

²¹ PSE Initial Brief ¶¶32-33.

²² The Joint Parties appear to have ignored the settlement negotiation privilege in bringing forward their subjective rationale for Exhibit E. This led PSE to argue its own perspective in like manner. This is not appropriate practice and should not occur in testimony or on brief.

capping the cost of these contracts is a way to offset costs that are likely to decline, such as depreciation of Colstrip and transmission facilities. While depreciation lowers cost of individual assets over time, PSE's asset acquisition may result in higher overall depreciation costs.

32 We also find unpersuasive PSE's argument that Exhibit E should be eliminated principally because it is inequitable. Whatever the parties' respective subjective intentions, the fact remains that the provision was part of a comprehensive settlement to which PSE agreed.

33 We find, however, that Exhibit E should be eliminated because it is more consistent with the fundamental purpose of any PCA program. The resources in Exhibit E fall into the power cost category, they have received regulatory approval, and the variability in the cost of these resources is outside the control of the Company. These are the types of costs for which PCA mechanisms are intended and we find they should be accurately accounted for in the true-up process. Whatever the original purpose behind asymmetrical treatment of these costs may have been, we do not find that the provision on its face is one that should survive into the future.

d. Costs associated with a new line of credit to support wholesale power hedging transactions.

34 The Joint Parties do not oppose this change but assert the hedging mechanism greatly reduces PSE's risk, an issue that should be considered in developing PSE's cost of capital in the Company's next general rate proceeding. We agree both that these costs should be included in the Power Costs Baseline Rate and that their possible impact on the Company's cost of capital requirements is a subject to consider in a future proceeding. We leave it to the parties to develop in PSE's next general rate case any arguments regarding whether inclusion of hedging costs in the baseline power cost rate should affect PSE's cost of capital.

2. Depreciation Tracker.

35 PSE proposes a new regulatory mechanism to track depreciation expense for transmission and distribution investments the Company makes between general

rate cases.²³ As proposed, depreciation expenses would be recovered through a surcharge added onto existing tariff schedules. The surcharge would be based on the incremental depreciation expense of natural gas and electric transmission and distribution investment over and above the depreciation expense reflected in existing rates. There would be an annual true-up. The mechanism would allow for *recovery of* investments in new plant between rate cases, but would not provide for *recovery on* the investments. As proposed, the depreciation tracker surcharge during the initial period would be \$7.9 million for electricity and \$10.9 million for natural gas.

36 PSE argues it needs the depreciation tracker to address regulatory lag. According to the Company, it will invest \$444 million and approximately \$500 million in energy (electricity and natural gas) delivery infrastructure during 2006 and 2007 respectively. PSE contends that while customers will benefit from investments in this transmission and distribution plant as soon as the infrastructure is put into service, the Company will not recover the depreciation expense it incurs or any return on its invested capital until the conclusion of its next general rate case following the plant's in-service date.

37 PSE undoubtedly recognizes regulatory lag is typical of rate base, rate of return ratemaking grounded in an historic test year adjusted for changes that are known and measurable at the end of that test year.²⁴ Indeed, the circumstances of which PSE complains are simply an inherent part of the historic test period approach, which requires the application of certain fundamental ratemaking principles that we and many other regulators endeavor to apply consistently over time. In particular, we disfavor and typically avoid single-issue ratemaking and we are careful to preserve so far as is reasonable the "matching principle" that relies on our consideration of all revenues, costs, and adjustments in the context of a test year with a definite ending date. Thus, PSE asks us to approve a novel mechanism that departs from fundamental principles of ratemaking.

²³ The mechanism would not apply to depreciation on generation investments, which can be addressed in a PCORC.

²⁴ Regulatory lag has both positive and negative attributes. On the positive side, for example, it is widely recognized that regulatory lag introduces beneficial discipline to management decisions and the company may reap the benefit of cost reductions between rate cases. On the negative side, there can be a significant gap in time between when useful plant is placed in service and when recovery in rate base is allowed on such investment.

- 38 PSE argues the Commission has in prior orders recognized it is appropriate to address earnings attrition when there is growing mismatch between revenues, expenses and rate base. According to the Company, it faces such circumstances due to regulatory lag and therefore its depreciation tracker or “known and measurable” rate base adjustment proposals are appropriate.²⁵ PSE states it has performed detailed attrition studies that demonstrate earnings attrition, thus justifying the requested relief.²⁶
- 39 It requires extraordinary circumstances to support a departure from fundamental ratemaking principles. In prior cases the Commission has required “a clear and convincing showing that the Company will be denied any reasonable opportunity to earn its authorized rate of return without extraordinary relief.”²⁷ We have considered the evidence PSE presented concerning attrition in some detail. Our analysis of the evidence leaves us unpersuaded that PSE will suffer earnings attrition as a result of not recovering depreciation on infrastructure investments it makes between rate cases.
- 40 Significantly, PSE’s attrition study assumes that the Commission will approve the Company’s proposed capital structure and rate of return on equity and does not assess other plausible scenarios. These assumptions are unfounded, as we discuss later in this order. Thus, the evidence PSE offers does not convince us that the Company’s capital investment between rate cases will erode its earnings at all, much less to the point that it will be denied a reasonable opportunity to earn its authorized rate of return.
- 41 PSE has not demonstrated financial circumstances that might justify the extraordinary relief represented by the proposed tracker mechanism. Nor has the Company demonstrated that regulatory lag will prevent it from making investments necessary to maintain reliable service to its electric and gas customers.

²⁵ PSE Brief ¶45-46.

²⁶ PSE Reply Brief ¶24.

²⁷ Staff Initial Brief ¶36 (citing *WUTC v. Washington Natural Gas Co.*, 4th Supp. Order at 29-30, Docket No. UG-920840 (September 27, 1993)); Reply Brief ¶38, fn. 61. *See also* Exhibit 526 (Russell). The Commission has granted extraordinary relief to utilities upon demonstration through attrition studies that circumstances are likely to prevent them from earning their allowed rate of return. Staff is correct to argue that such relief should be granted only under extraordinary circumstances and with clear evidence that the utility would be harmed without such relief.

42 In short, the record simply does not support and we cannot approve a novel mechanism to change rates that will shift risks and costs to ratepayers without the benefit of a full review of revenue and expenses.²⁸

3. Post-Test-Period Adjustments to Rate Base

43 Although PSE advocates on brief for its proposed depreciation tracker, discussed above, the Company also states that a rate base adjustment for post-test period investments put into service through June 30, 2006, would be an acceptable alternative to the tracker mechanism.²⁹ Indeed, several parties state this would be acceptable to them and propose various alternatives.³⁰ Each of these alternatives is different and would have significantly different rate impacts. They are styled as pro forma adjustments to test-year depreciation expense or rate base, or both, to account for non-revenue producing electric and natural gas distribution or transmission projects completed and put into service after the close of the test-year. We refer collectively to these adjustments as “out-of-period adjustments.”

44 PSE initially proposed to include adjustments to reflect the costs of more than 6,000 projects completed and put in service between October 2005 and June 2006. Staff and others objected that this list, including more than 20,000 line entries, could neither be audited nor verified in the time available, if at all. Staff proposed in its brief that it would be reasonable for the Commission to approve, as out-of-period adjustments to rate base, three gas projects and two electric projects. Staff’s criteria were that these projects were required either to fulfill reliability standards, such as the Western Electricity Coordinating Council (WECC) reliability criteria or to meet the terms of prior Commission orders. The total additions to rate base for these projects would be \$15.3 million for electric rate base and \$10.6 million for natural gas rate base.

²⁸ The Commission has approved for PSE a PGA, a PCA, the PCORC process, storm cost deferral, and demand-side management tariff-riders. Under these various mechanisms, and via regular general rate proceedings, we have authorized increases in the Company’s rates a number of times since 2002, often in expedited proceedings, keeping the Company’s revenues abreast of its demonstrable needs.

²⁹ PSE Initial Brief ¶43; PSE Reply Brief ¶25.

³⁰ Specifically, Federal Executive Agencies (FEA) in its response case, PSE in its rebuttal case and reply brief and Staff in its brief, propose alternatives to the tracking mechanism.

- 45 FEA proposed an alternative adjustment to rate base that would allow PSE recovery “of” but not recovery “on” the Company’s transmission and distribution projects put in service through June 30, 2006.³¹ FEA does not calculate the amount of its recommended addition to rate base.
- 46 On reply, PSE contends the Staff’s proposal to allow a one-time rate base adjustment for a limited number of projects concedes the point that the Commission should approve some out-of-period adjustments. PSE argues, using the Staff criterion, that three additional electricity transmission and distribution projects should be included: Novelty Hill (\$23 million), Foss-Bangor (\$7.9 million) and March Point (\$4.8 million). This would increase the total out-of-period adjustments to electric rate base to \$51.2 million.
- 47 Public Counsel argues against any out-of-period adjustment, predicting that if “piecemeal” adjustments are made to rate base in this case other utilities will “jump on the bandwagon.”³² We share this concern, as a general proposition, and are equally concerned about its implications for our regulatory oversight.³³
- 48 We are more concerned in this case, however, that there is very little evidence concerning the specific plant additions individual parties propose we allow as out-of-period adjustments to rate base or for determining allowed depreciation.³⁴ FEA, through its witness Ralph C. Smith, is the only party that addressed this issue in its case in chief. Mr. Smith’s testimony, however, does not identify any specific plant additions.³⁵ Ms. McLain and Mr. Story testified on rebuttal, but offered little more detail than provided by Mr. Smith. Mr. Russell testified briefly on surrebuttal, and Ms. McLain and Mr. Story with similar brevity on sur-surrebuttal.
- 49 While these witnesses mention a few major projects by name, they provide far less information than we typically require when evaluating whether to allow additions

³¹ FEA Initial Brief ¶¶48-54. {pp. 22-24}; FEA Reply Brief.

³² Public Counsel Reply Brief ¶28.

³³ Among other concerns, by allowing inter-period adjustments to rate base we reduce the companies’ incentives to file general rate proceedings with reasonable regularity.

³⁴ PSE’s and Staff’s proposals would allow for recovery of (*i.e.*, depreciation) and recovery on (*i.e.*, return) the out-of-period additions to rate base. FEA would only allow PSE to recover in rates the associated depreciation expense.

³⁵ Exhibit 492 at 14:7-19:4.

to rate base even for plant placed in service during the test year. We have scant basis upon which to determine the prudence of these post-test period investments or to determine whether and to what extent they may be used and useful. These determinations should not rest on speculation.

50 In sum, the various proposals for out-of-period adjustments come too late in this proceeding and are supported by too little evidence. Nor have the requirements of due process been fully met. Given that, we could not approve these out-of-period adjustments even were we otherwise so inclined.

51 Although we find this record insufficient to support out-of-period adjustments, there is nothing that precludes PSE from seeking additions to rate base between rate cases so long as the amounts are not so large as to trigger a general rate proceeding under our rules. If the investments are shown to be prudent, the amounts are reasonable, and the plant is demonstrated to be used and useful, the Commission may exercise its discretion to allow recovery in rates. Important considerations guiding that discretion would be whether there has been a very recent general rate proceeding or the Company commits to making a general rate filing soon after the additions are allowed.³⁶

52 In this proceeding, for the reasons stated above, we will not authorize any out-of-period adjustments to rate base.

B. Risk Mitigation Proposals—Gas

1. Decoupling

53 Decoupling is a ratemaking and regulatory tool that breaks the link between a utility's recovery of fixed costs and a customer's energy consumption. From a utility perspective, it is a means to ensure recovery of a significant part, or even all of its fixed costs regardless of reduced consumption. One potential source of reduced consumption, at least on a per customer basis, is conservation undertaken by individual customers. Consumption may also be lower at times for other reasons including more energy efficient building codes and appliances, improved insulation, warmer than normal weather, and, of course, price elasticity.

³⁶ See supra ¶¶24-27 (discussion re paragraph 10 of the PCA).

- 54 Conservation advocates and others recognize decoupling as a potentially important tool to promote conservation. This is the primary rationale Staff and NWECA rely upon for decoupling. We acknowledge that improved energy savings from cost-effective conservation, which we strongly support, is a highly appealing rationale for decoupling on its face. We emphasize, however, that decoupling is a merely one regulatory tool in a larger toolbox of devices we might use to promote greater conservation. Indeed, as discussed separately below, we consider and approve in this proceeding an alternative means to promote conservation of electricity through the use of direct incentives and disincentives to the Company—rewards for reaching, and penalties for failure to reach conservation targets. As we also discuss later in this section, this alternative might offer similar promise in terms of promoting conservation of natural gas.
- 55 As the parties argue, decoupling is principally useful in circumstances where there is a need to promote a more positive company attitude toward conservation by removing what may be a disincentive, or barrier to aggressive pursuit of conservation; as consumption declines so may a company's recovery of that portion of its fixed costs embedded in volumetric rates. As we noted in the conclusion of our recent rulemaking, the question of whether decoupling is appropriate and necessary can only be answered in the context of a particular company's circumstances. Our statutory responsibility to regulate in the public interest requires us to look beyond the abstract and examine the evidence to determine whether the facts support this rationale in PSE's case.³⁷
- 56 PSE proposes a decoupling mechanism that it calls the Gas Revenue Normalization Adjustment (GRNA), which is intended to ensure that PSE receives the authorized per customer "margin revenue" regardless of variations of sales volumes due to weather, conservation, or other causes.³⁸ For each affected service schedule, PSE would determine the annual contribution towards margin and then a

³⁷ The Commission learned in a 2005 rulemaking proceeding that it is not desirable to take a blanket approach to decoupling. "The Commission believes that the wide variety of alternative approaches to decoupling make it more efficient to address these issues in the context of specific utility proposals included in general rate case filings rather than through a generic rulemaking." Rulemaking to Review Natural Gas Decoupling, Docket No. UG-050369, Notice of Withdrawal of Rulemaking (October 17, 2005).

³⁸ The term "margin revenue" refers to the revenue necessary for a utility to recover its total cost of service net of purchased gas expenses and other expenses treated as "flow-through" items in rates (*e.g.*, revenue taxes, conservation program riders). A utility's per customer margin revenue is simply its total cost of service, as determined in the most recent general rate case, divided by the number of customers.

monthly margin revenue target.³⁹ At the close of each month, the Company would defer the difference between the actual margin revenues and the target margin revenues. At the end of the year, PSE would compute a schedule-specific surcharge or credit to recover or refund the deferral balance over the following year.

- 57 PSE's proposed GRNA would account for all sources of lost margin including, for example, warmer than normal weather, utility-sponsored conservation, and improved building and appliance efficiency standards. According to PSE, the GRNA would prevent the over- or under-collection of margin due to the effects of conservation and weather. In fact, PSE identifies weather normalization as a "critical component" of its decoupling proposal and states:

The GRNA is designed to help stabilize the level of gas margin revenues that are recoverable from customers on an annual basis. It will periodically adjust the Company's distribution service rates to recover the margin revenues per customer, as established in this general rate case, that fluctuate due to variances in gas volumes caused primarily by weather, energy efficiency gains and conservation efforts.⁴⁰

- 58 Although supporting decoupling in principle, Staff recommends we reject PSE's proposal in favor of a three-year pilot decoupling mechanism that would allow the Commission to examine its effects on promoting energy conservation. Staff's proposal, however, would only address non-weather related variation in sales volumes and would include only certain residential, commercial and industrial schedules.⁴¹ Staff also proposes a new-customer adjustment to take into account that new customers have lower than average usage.⁴²

³⁹ PSE proposes to apply its decoupling mechanism to five service schedules:

- Residential General Service Schedule 23
- Commercial and Industrial General Service Schedule 31
- Special Commercial Heating Service Schedule 36
- Special Multiple Unit Housing Service Schedule 51
- Propane Service Schedule 53

⁴⁰ PSE Initial Brief ¶89.

⁴¹ I.e., Schedules 23, 31 and 36. Exhibit 561 (Steward) at 8-20.

⁴² *Id.*

- 59 NWEC also supports decoupling as a three-year pilot but would apply it only to the residential class. NWEC proposes that annual rate adjustments be limited to three percent and that recovery of approved margin be tied to achievement of certain energy efficiency targets. On rebuttal, PSE opposes both the proposed annual rate limit and the performance measure.
- 60 Public Counsel opposes any decoupling program.⁴³ Public Counsel argues that the principal effect of PSE's decoupling proposal, like the Staff and NWEC alternatives, is simply to guarantee PSE's revenue and, perhaps, to generate what Public Counsel terms windfalls for the Company.
- 61 For all of its ostensible advantages, decoupling also has disadvantages, notably the shifting of risk to ratepayers, including the risk of fluctuations in weather under the Company's proposal. Under PSE's proposal, at the end of a warmer than average year, customers on the system for the following year will be required to pay surcharges to ensure that PSE recovers all of its fixed costs from the prior period. All customers will experience these surcharge rates regardless of lower use by individual customers and lower use overall. Granted, some customers will benefit in a colder than normal year when the Company over-recovers its fixed costs and credits continuing customers' bills in the following year.⁴⁴ This, however, points us to a second potentially serious problem; the distortion of price signals and consequent dampening of customer conservation initiatives.
- 62 Balancing fixed cost recovery on an annual basis via a surcharge or credit mechanism diminishes the value of rates as a means to send appropriate price signals to customers. Based on changing energy market conditions, price signals undoubtedly affect individual customer choices to conserve or not. This price signal may be weakened if customers conserve and then are faced with paying a surcharge that reduces their financial benefit. Just as we must be concerned that in some instances the absence of decoupling or something similar may prove a disincentive to a company promoting conservation, the presence of decoupling, and associated surcharges, may prove a disincentive to customers who might be inclined to conserve if it is to their financial advantage.

⁴³ Exhibit 506 (Brosch), at 3, 18-21.

⁴⁴ We note in this connection the disadvantage of a surcharge mechanism resulting in a degree of mismatch between customers whose usage patterns contribute to over- or under-recovery and customers who receive a credit or must pay a surcharge.

- 63 A third potential problem, vigorously argued by Public Counsel, is the risk over time of distorting the “matching principle.”⁴⁵ Costs and revenues are carefully balanced or “matched” in a general rate case. If a company is largely assured recovery of fixed costs and most variable costs are routinely passed through to customers (*e.g.*, via purchased gas adjustment mechanisms and the like), then there is less reason for the company to file a general rate case. In this context, any cost savings achieved by the company are not shared with customers. The result risks over-earning by the company and over-paying by the customers.
- 64 Considering this, and bearing in mind the burden of proof lies with the Company we must examine carefully whether the record in this proceeding is sufficient to prove the potential advantages from decoupling outweigh its potential disadvantages in PSE’s case.
- 65 PSE has an outstanding record in terms of encouraging conservation and achieving significant amounts of conservation on its system over time. Indeed, as PSE observes in its Initial Brief: “It is uncontested that PSE is making great efforts at energy efficiency, both electric and gas.”⁴⁶ While we commend the Company’s efforts and success in this regard, and recognize the apparent irony in its effect on our analysis, it is nevertheless true that if there is little or nothing to be gained from implementing a decoupling mechanism in terms of increased Company conservation efforts, then there is no conservation rationale to approve a program. Decoupling is a means to an end, not an end in itself. It is neither an entitlement nor a reward. Considering this, we reject suggestions in several parties’ briefs that if we do not authorize decoupling in this proceeding we are somehow penalizing PSE for its longstanding commitment to conservation.
- 66 Some parties argue that decoupling is an important tool in shaping corporate culture so that utilities will aggressively implement, or at least be open to pursuing conservation measures. This makes sense in the abstract, and may prove to be true in the case of individual companies. Decoupling, however, is not necessary to infuse PSE’s corporate culture with such an attitude. PSE’s corporate culture insofar as conservation is concerned is strongly favorable, and has been for many

⁴⁵ Public Counsel Initial Brief at ¶¶45-47

⁴⁶ PSE Initial Brief at ¶92 (citing Harris, Tr. 115:13 – 116:22, 120:8 – 122:7; Amen, Tr. 499:15-24, 530:11-20; Exhibit 561 (Steward) at 10:10-18).

years. As Ms. Harris testified: “Our conservation programs span decades; we have been a leader in conservation for decades.”⁴⁷

- 67 Mr. Shirley testified that the Company has an active conservation program on the gas side that developed without decoupling.⁴⁸ Significantly, it appears from Mr. Shirley’s testimony that the Company has exploited, for the time being at least, most or all of the cost-effective gas conservation programs available.⁴⁹ Nevertheless, the Company continues to pursue every possibility for cost-effective gas conservation measures. PSE’s performance in this regard is confirmed by Staff.⁵⁰ While decoupling might in theory remove any disincentive that arguably is a barrier to PSE investing in more gas energy efficiency measures, if there are not additional cost-effective measures in which to invest, no conservation benefit is gained by implementing decoupling.⁵¹
- 68 In addition to the fact that the decoupling proposals advanced in this proceeding apparently will have little to no effect on the amount of conservation pursued by PSE, we find other reasons to reject the proposals. One reason is that without an earnings cap or some other mechanism to preserve some degree of risk for the Company, this type of mechanism, along with the PGA, makes it even less likely that PSE will file general rate cases. As previously noted, the risk of over-earning is a concern assuaged by periodic rate cases and consequent Commission oversight. Further, without performance measures, neither the Commission nor the public can evaluate whether or to what extent decoupling is actually promoting incremental amounts of conservation. Yet, PSE opposes any sort of earnings cap or performance measure.
- 69 Finally, our consideration and approval of an electric conservation incentive mechanism in this proceeding persuades us that such approaches may more effectively target the goal of increasing PSE’s conservation efforts than does decoupling. Incentive programs are simple to implement, easy to understand, very direct in their operation and easier to evaluate. Though there is no basis to establish such a program in this proceeding given the Company’s decision to

⁴⁷ Shirley, Tr. 115:20-22.

⁴⁸ Shirley, Tr. 585:6-10.

⁴⁹ Shirley, Tr. 618:20-623:3.

⁵⁰ Steward, Tr. 765:19-23; 767:9-768:5.

⁵¹ Neither the Company, nor Staff proposes that specific conservation goals be implemented in connection with decoupling. In fact, PSE actively opposes the idea of such goals.

pursue decoupling on the gas side to the exclusion of an incentive program, this may be an approach the Company could explore in a future filing.

C. Capital Structure and Cost of Capital

- 70 PSE's currently authorized rate of return (ROR) is 8.40 percent with a return on equity (ROE) of 10.3 percent and an equity ratio of 43 percent. The Commission set these factors on February 18, 2005, in Order No. 6, in Docket Nos. UG-040640 and UE-040641 (consolidated). In this docket, filed just 12 months later, the Company requested an overall rate of return of 8.76 percent based on a return on equity of 11.25 percent and an equity component of 45 percent.⁵²
- 71 Table 5 summarizes PSE's currently approved capital structure and cost rates and the recommendations of the Company, Staff and ICNU on brief. Our determinations, discussed in detail below, are shown in Table 6.

TABLE 5
Capital Structure and Cost of Capital Proposals

	Commission Approved in Dockets UE- 040641/UG- 040640		Company Proposal		Staff Proposal		ICNU Proposal	
	Share/Cost		Share/Cost		Share/Cost		Share/Cost	
Equity	43.00	10.30	45.00	11.25	43.00	9.38	44.13	9.90
Long-Term Debt	47.53	6.88	48.44	6.64	47.88	6.64	49.71	6.64
Short-Term Debt	3.11	4.81	2.11	6.66	4.67	6.66	.90	6.22
Trust Preferred	6.32	8.60	.70	8.54	.70	8.54	5.22	8.54
Preferred Stock	.04	8.51	3.75	7.61	3.75	7.61	.04	7.61
TOTAL ROR	8.40		8.76		7.87		8.17	

⁵² None of the three expert witnesses in this case develops a recommendation by identifying relevant market circumstances that have changed since the Commission's determination in this recent order.

TABLE 6
Commission Determination of Capital Structure and Cost of Capital

	Share %	Cost %	Weighted Cost %
Equity	44.00	10.40	4.58
Long-Term Debt	48.00	6.64	3.19
Short-Term Debt	2.70	6.66	0.18
Trust Preferred	5.25	8.54	0.45
Preferred Stock	0.05	7.61	0.00
TOTAL ROR			8.40

1. Capital Structure

72 In its most recent order approving PSE's capital structure the Commission set the equity ratio in the Company's capital structure at the level found "most likely to prevail, on average, over the course of the rate year."⁵³ Mr. Gaines, for the Company, recommends a capital structure that includes 45 percent equity based on what the Company asserts are the planned levels of capitalization for the rate year: January 2007 through December 2007.⁵⁴ Mr. Gaines argues, among other things, that the Company requires a higher share of equity capitalization because it "faces an unprecedented level of capital spending to support new customer additions, replace aging infrastructure and to add new electric generating resources." According to Mr. Gaines, these capital needs cannot be funded by internal cash flows.⁵⁵

73 Mr. Hill, for Staff, recommends a capital structure that holds constant the currently approved 43 percent equity share and modifies the Company's requested structure by replacing approximately \$100 million of projected equity capitalization with short-term debt.⁵⁶

⁵³ *WUTC v. PSE*, Docket Nos. UG-040640 and UE-040641 (consolidated), Order No. 6 (February 18, 2005) ¶40.

⁵⁴ Exhibit 136C at 1.

⁵⁵ Exhibit 131CT (Gaines Direct) at 6.

⁵⁶ Exhibit 531CT (Hill Direct) at 37.

- 74 Mr. Gorman, for ICNU, recommends a capital structure equivalent to the Company's 2005 year-end actual capitalization.⁵⁷ Mr. Gorman argues that the Company's proposed capital structure is hypothetical and is not based on known and measurable data.
- 75 Thus, determining capital structure in this case boils down to our resolution of two issues:
- 1) Should a hypothetical equity share be approved based on the Company's rate year projections?
 - 2) If equity share is based on historical data, what average or point in time should be used?
- 76 The Commission has approved hypothetical capital structures when there was a clear and compelling reason to do so. The Company is correct when it states that the last two capital structures approved by the Commission were based on projected or anticipated rate year capitalization. However, this was an exercise of judgment considering facts and circumstances shown at the time to be relevant, not a policy determination by the Commission. In these prior cases, the Commission was focused on balancing economy and safety by reducing the Company's leverage and improving the safety in its balance sheet. In this case, the Company's balance sheet has improved substantially from its over-leveraged condition that prevailed during 2000 and 2001.
- 77 The Company contends that it needs a higher equity share to support its projected high level of capital expenditure. The Company does not contend that its current balance sheet is too weak to attract capital, just that a stronger balance sheet might improve its debt rating and reduce its borrowing costs. Staff makes a detailed case for why the Company's balance sheet and access to capital is sufficient at its current rates, rate of return and capital structure to support the capital program which, according to Staff, actually peaks in 2006.⁵⁸

⁵⁷ Exhibit 471CT (Gorman Direct) at 5.

⁵⁸ The Company disagrees, replying that the construction program forecasts included in the 2005 10-K and rating agency presentations do not include new generation assets for 2007 and 2008 and that its Board has not approved the resource acquisition plans for 2007 and beyond, which it expects to be significant. PSE Reply Brief ¶50 fn. 89.

- 78 It may be that the Company will increase its actual equity ratio with either debt retirements or new issuances of stock during the rate year, but ICNU and Staff are correct to argue that at this point this is only speculation. The record does not demonstrate a compelling reason to approve a capital structure that contains more equity than is actually supporting the Company's operations, and there is no certainty that the Company will actually increase its equity share during the rate year. Consequently, we find an actual rather than hypothetical capital structure should be used in this case.
- 79 Turning to the historic data, ICNU proposes we use the Company's actual equity share at year-end 2005, which was 44.13 percent.⁵⁹ PSE states that an equity share of at least 44 percent was maintained through June 30, 2006. Both of these figures are known, in contrast to the projections on which the Company relies for its 45 percent rate-year average and on which Staff relies to demonstrate a ratio of 40 percent at year-end 2006.
- 80 Because it is based on a known change from test-year figures and is supported by the actual equity ratio through June 2006, we find a 44 percent equity share reasonable and we will use that equity share in our return calculations. To improve consistency in the pro forma adjustment of the capital structure we also adjust the Company's short-term debt ratio to reflect the mid-point of short-term debt balances carried by the Company between December 31, 2005, and June 30, 2006. The Company's 10-Q shows the mid-point to be close to 2.7 percent.⁶⁰ The Company's 10-Q shows no variation in Trust Preferred or Preferred Stock between these periods. We find no adjustment to these components necessary.⁶¹ In light of our other determinations, we find 48 percent is a reasonable share for the Company's long-term debt.

⁵⁹ The test year in this proceeding ended September 30, 2005.

⁶⁰ Exhibit 466 at 16 (Valdman).

⁶¹ We note that both the Company and the Staff propose a share of preferred stock that varies significantly from the actual figures in the test-year, year-end 2005, and June 2006. Presumably the Company's figure is based on its 2007 rate-year projection, but it makes no specific argument regarding preferred stock. Staff appears to use the 2007 rate-year projections for preferred and trust-preferred, rather than actual figures for the test-year, December 2005 or June 2006.

a. Cost of Equity

81 We determine that PSE's cost of equity capital should be set at 10.4% for purposes of setting rates in this proceeding. Coupled with our decision to set PSE's equity share at 44%, the Company's computed weighted average cost of equity is 4.58%.

82 The Commission introduced its discussion of cost of equity evidence in PSE's most recent general rate order with this observation:

The parties are far apart on the cost of equity component that they contend should be embedded in rates. The record includes cost of capital evidence offered in support of a range of values from 8% to 12.9%, with parties advocating results in the range of 9.00% to 11.75%. Coupled with the various capital structures advocated, this produces overall return results ranging from Staff at 7.80%, Public Counsel at 8.01%, and PSE at 9.12%.

83 Not counting analytic exhibits and hearing transcripts, we have over 400 pages of testimony on the appropriate cost of equity capital for PSE in this proceeding. Several parties devote significant parts of their briefs to this issue. Yet, the parties are not much closer to agreement today than they were two years ago, and their analyses and results exhibit markedly similar ranges to what we considered just over one year ago. The analytic evidence in this proceeding produces a range for cost of equity from 7.38 percent to 12.85 percent with advocated results ranging from 9.37 percent to 11.25 percent.

84 Little of the extensive testimony offered on this subject focuses squarely on what might have changed in the capital markets or at PSE in the last 18 months to justify a change in the ROE set by the Commission in February of 2005. Instead, as usual, most of the testimony focuses on familiar, rather academic disputes regarding methods, theory and assumptions. To be sure, these disputes affect the level of the experts' ROE estimates, but when they are boiled down to substance, we find that a few key assumptions drive the differences among the analytic results and the recommendations of the three parties. These assumptions are matters of judgment tempered by differing professional orientations. We must look beyond the experts' Discounted Cash Flow, Capital Asset Pricing Model and

similar analyses to a broader body of evidence to make our determinations, which are informed by, but not dictated by the experts' modeling results.

- 85 We do find evidence of some changes in PSE's circumstances that influence our consideration of this issue. PSE's capital program has grown from forecasts of \$400 million and \$471 million made in 2004 for the years 2006 and 2007, to forecasts of \$854 million and \$670 million respectively.⁶² It appears, however, that the Company has been able to cover these costs through managing its internal cash flows and issuing new equity and debt without overly taxing remaining borrowing capability. The Company's credit rating has not been downgraded and its stock price recently has been relatively stable.
- 86 Interest rates in the capital markets have increased, though mainly in the short-term part of the yield curve. The record in the 2005 general rate case contained a forecasted 30-year treasury rate of 4.89 percent. The record in this case includes 30-year treasury forecasts of 4.97 to 5.3 percent—an average of 5.14 percent. By this comparison, forecasted long-term risk free interest rates have increased by about 25 basis points.
- 87 Given that we are not approving various new risk mitigation proposals made in this proceeding that would affect the balance of risks between PSE and its customers, the weight of the evidence falls on leaving the equity return unchanged or only slightly higher. The expert testimony suggests to us a figure in the range between 10.3 percent and 10.5 percent would be proper. We find 10.4 percent well supported by the record and appropriate, considering the end results achieved.

2. Capital Structure and Cost of Capital Summary

- 88 We summarize our determinations of the issues concerning Capital Structure and Cost of Capital above in Table 6.
- 89 Our findings and conclusions concerning the appropriate capital structure and component cost rates produce an overall weighted cost of capital of 8.40 percent. The evidence shows this overall rate of return will be sufficient to attract the

⁶² Exhibit 801.

capital the Company may need for infrastructure expansion while at the same time producing financial ratios measuring interest coverage and debt leverage solidly within the ranges required for BBB credit ratings by Standard & Poor's and other rating agencies.⁶³ With this foundation, and considering the PCA mechanism, PCORC, the purchased gas adjustment (PGA) mechanism and other risk mitigation programs the Commission has previously approved, the Company should have every opportunity, with strong management and improvements in efficiency, to further improve its credit rating and strengthen its overall financial health.

D. Revenue Requirements

1. Electric

- 90 As previously mentioned, only PSE and Staff put on full revenue requirements cases. PSE originally requested increases of \$148.8 million, or 9.21 percent for electric service and \$51.3 million, or 5.34 percent for gas service.
- 91 On July 7, 2006, PSE amended its electricity revenue request via supplemental direct testimony to reflect the additional revenue approved in Docket UE-060783, which updated the Company's base power costs. PSE's amended electricity revenue request was reduced to \$42.9 million and its amended natural gas revenue request was reduced to \$39.2 million.
- 92 By the time of its rebuttal case, PSE asserted the need to recover a revenue deficiency of \$33,778,533 in electric rates, a 1.9 percent increase.⁶⁴ On the gas side, PSE asserted a revenue deficiency of \$39,008,416.⁶⁵ PSE proposed a 4.06 percent rate increase to recover this amount.
- 93 Staff contended in its response case that the company should be required to reduce rates to reflect excess revenue of \$40,698,572.⁶⁶ Staff argued in the response round of testimony that the company's revenue deficiency on the gas side is \$19,348,874.⁶⁷

⁶³ Exhibit 10.

⁶⁴ Exhibit 439 (Story Rebuttal).

⁶⁵ Exhibit 232CT (Karzmar Rebuttal) at 2:4-8.

⁶⁶ Exhibit 521 (Russell Response).

⁶⁷ *Id.*

94 On September 15, 2006, PSE and Staff filed their Agreement on Revenue Requirement Adjustments. PSE and Staff agree to all but 4 issues that potentially impact the electric revenue requirement:

- Rate of Return,
- Power Cost
- Directors & Officers (D&O) insurance
- Depreciation Tracker

95 We discussed previously and resolved the issues related to rate of return and the depreciation tracker proposals. As to proposed adjustments to the electric revenue requirement, then, only two remain in dispute. Our resolution of the D&O insurance adjustment impacts the gas revenue requirement as well.

96 We digress briefly to caution that while we approve the revenue requirement agreement between PSE and Staff, and resolve only the few issues disputed between the parties, we have an independent concern about the recovery of executive compensation. We recognize that the activities of the executive officers of regulated companies such as PSE confer some benefit on the ratepayers, but the officers' fiduciary responsibilities run to the shareholders, not the ratepayers. This is a fact that we must keep in mind in considering what part of executive compensation is appropriate for recovery in rates.

97 Because it was not expressly identified as an issue in this proceeding, we do not have a record sufficient to evaluate whether there should be some adjustment to the amount of executive compensation allowed for recovery in rates. However, we can and do make clear that we wish to see this subject fully developed on the record in any future case that includes proposed increases in this expense.⁶⁸ We do not suggest it is within our purview to dictate to the board of directors the level of executive compensation and performance benchmarks it should approve, but in this era of substantially escalating executive compensation we are obligated to consider how much the ratepayers of a regulated monopoly should be required to pay.

⁶⁸ We do not single PSE out in this regard. We will have the same expectation in proceedings involving other companies we regulate.

- 98 Returning to the adjustments that are expressly contested in this proceeding, we summarize the parties' positions in Table 7 below. Our discussion and decisions follow.

TABLE 7
Contested Restating and Pro Forma Adjustments – Electric and Gas

Adjustment Description	Company Position		Staff Position	
	Revenue requirement	Net operating income	Revenue requirement	Net operating income
Electric				
Power Costs	312,839,936	(194,190,197)	293,563,457	(182,224,643)
Director and Officer Insurance	21,412	(13,291)	(508,371)	315,563
Gas				
Directors and Officers Insurance	14,392	(8,946)	(341,697)	212,399

a. Contested Adjustments

i. Power Costs

- 99 The Power Cost Baseline Rate is the expected level of power costs around which the Company's power cost adjustment mechanism works. The Company's filing would set annual power costs at \$966 million, an approximate \$91 million increase from current levels set via a compliance filing in June 2006, as required by the Commission's Order approving the Company's 2005 PCORC.⁶⁹
- 100 Staff, Public Counsel and ICNU (Joint Parties) recommend a \$19.2 million reduction to PSE's revenue requirement for power costs relative to the Company's June 2006 compliance filing. Roughly one-third of the proposed reduction is related to adjustments to AURORA model⁷⁰ inputs and two-thirds is related to adjusting the AURORA output to reflect market prices for sales and purchases of

⁶⁹ Exhibit 260.

⁷⁰ AURORA is the power cost model PSE used to estimate net power costs within the west-wide grid of utilities. The AURORA model includes fuel costs, plant statistics and costs to buy and sell power.

wholesale electricity at the mid-Columbia trading hub. On brief, ICNU speaks for the Joint Parties.⁷¹

Updated Natural Gas Costs

- 101 The Joint Parties argue PSE should be required to update its power cost projection to reflect natural gas prices that decreased subsequent to the Company's supplemental filing. The Company's supplemental filing on July 7, 2006, included power costs based on an \$8.57/MMBtu average price at Sumas for the rate year. However, as of September 20, 2006 (the time of the hearing), the Joint Parties state the average Sumas gas price for the 2007 rate year was less than \$7.00/MMBtu.⁷² This is incorrect. As shown on the exhibit the Joint Parties cite, the \$7.00 price is a daily price, not an average price. The three-month average price near the end of September 2006 was \$8.09, as PSE acknowledges.
- 102 The Joint Parties contend that the Company should be required to file a gas price update based on an average of 2007 forward market prices from the three-month period September 1, 2006, through November 30, 2006. They point to the Commission's prior statement: "power costs determined in general rate proceedings and in PCORC proceedings should be set as closely as possible to costs that are reasonably expected to be actually incurred during short and intermediate periods following the conclusion of such proceedings."⁷³
- 103 PSE states that it does not object to updating its power cost projections for the rate year. However, the Company asserts that it would be insufficient to update only natural gas prices. According to the Company, other changes in the 2007 power portfolio that are now known should also be included if power cost projections for the rate year are to be updated.⁷⁴
- 104 The Commission has stated its preference for updated gas costs in prior cases, relying on much the same methodology and similar data to what is present in our

⁷¹ Staff relies on ICNU and Public Counsel to present its argument on power costs "...Staff adopts the arguments presented [by Public Counsel and ICNU] in their briefs on those subjects." (Staff Brief ¶6, fn 11) Public Counsel, for its part, "...adopts the ICNU brief on this issue." (Public Counsel Initial Brief ¶130).

⁷² ICNU Initial Brief ¶12 (citing Exhibit 289C).

⁷³ *WUTC v. PSE*, Docket No. UE-040641, Order No. 06 (Feb. 18, 2005) ¶108. ICNU Initial Brief ¶¶11-14.

⁷⁴ PSE Initial Brief ¶109.

record here.⁷⁵ The method for calculating such costs is now well-established. The update should be a straightforward, mechanical and non-controversial process. We determine that PSE should be required to update gas costs using the three-month average through the end of November 2006 when it reruns AURORA in support of its compliance filing in this proceeding.

- 105 As to the other costs PSE proposes be updated, costs it does not identify except by reference to brief redirect examination of Company witness David Mills, there simply is no record to support any such update even were we otherwise inclined to authorize it. While there are few if any questions of fact regarding the price of natural gas at the Sumas trading hub, we simply cannot know what disputes may arise over other potential changes in the power portfolio that PSE would propose. Accordingly, while we find it appropriate for PSE to rerun AURORA with updated gas costs, we do not find support in the record for updating other costs.

Hydro Shaping

- 106 The Joint Parties argue the “shaping factors” PSE used in its AURORA modeling do not produce reasonable generation amounts during the more valuable on-peak periods.⁷⁶ The Joint Parties point to PSE’s April 14, 2006, position and exposure report and assert it shows that PSE expects to achieve higher levels of peak period hydro generation than it has assumed in its AURORA modeling. The Joint Parties further assert that PSE’s AURORA hydro-shape conflicts with the hydro shaping factors used in the BPA’s 2006 Risk Analysis Study Documentation. The shaping factors recommended by the Joint Parties would reduce PSE’s power costs by \$6.0 million.⁷⁷
- 107 PSE says its position and exposure report provides the Company with a “stretch goal” to maximize the value of hydro resources for operational purposes, but does not capture certain dynamic variables that impair the Company’s ability to actually optimize this resource.⁷⁸ Mr. Mills, in fact, identified several factors that limit the

⁷⁵ ICNU Reply Brief ¶7. See *WUTC v. PSE*, Docket No. UE-050870, Order No. 04, ¶16 (Oct. 20, 2005).

⁷⁶ The “shape” of hydro generation between on-peak and off-peak periods is an input to the AURORA model.

⁷⁷ ICNU Initial Brief ¶¶28-30, ICNU Reply Brief ¶¶12-13.

⁷⁸ Exhibit 269C (Mills) at 24:11-16.

Company's ability to optimize hydropower generation between on-peak and off-peak hours.⁷⁹ These factors include:

- Environmental restrictions (fish protection).
- Reservoir restrictions (flood control).
- Loading factors (system coordination).
- Unit outages.
- Operating reserves.
- Wind integration.

PSE further states that over the last five years it has been able to shape only 62.1% of its hydro generation into peak periods, an amount lower even than the AURORA rate year projections of 64.5%.⁸⁰

108 The operational constraints on PSE's ability to operate its hydro resources in a theoretically optimum way are real and must be taken into account in determining power costs. It does not appear that the Company's position and exposure report or BPA's Risk Analysis Study takes account of these limiting factors on PSE's ability to generate additional hydro during peak periods. PSE did take these factors into account in its AURORA modeling. We find PSE's hydro shaping is reasonable for purposes of running AURORA, including the rerun for natural gas costs we require to support the Company's compliance filing in this proceeding.

Minimum Up and Down Times for Gas-Fired Combustion Turbines

109 The AURORA model's developer, EPIS, Inc., furnishes much of the input data PSE and other utilities rely on when running the model. These data include the operating characteristics of generating resources in the western United States. The Joint Parties assert that PSE made no effort to verify the accuracy of operating parameters for generating resources not owned by the Company and that the supplied data included overly restrictive minimum up- and down-times for large combined cycle combustion turbines (CCCTs).⁸¹ The Joint Parties would replace

⁷⁹ *Id.* at 25:6-26:28.

⁸⁰ PSE Initial Brief ¶115.

⁸¹ The minimum up-time for a resource is the minimum number of hours that a resource must operate continuously, and the minimum down-time is the minimum number of hours that a facility must remain shut down before starting up again.

the EPIS-supplied up- and down-times (*i.e.*, 16 hours on and 8 hours off) with what they allege are “more realistic values of a minimum up time of 6 hours and a minimum down time of 4 hours.”⁸² The Joint Parties calculate that using these modified run times would lower PSE’s costs by \$2.4 million.⁸³

110 PSE agrees that most CCCTs are physically capable of operating as the Joint parties recommend, but Mr. Mills’ testified that several factors preclude CCCTs from being operated in this way:

- Increased maintenance costs.
- Air quality and other permits.
- Operating contracts.
- Physical characteristics of some plants.⁸⁴

It is highly unlikely that any individual utility has the wherewithal or access to necessary data to develop operational parameters for each regional generating resource. Nor has ICNU obtained and relied on such data. It is reasonable for the Company to rely on the vendor of the AURORA model to supply this type of data. We find PSE’s use of EPIS-supplied run times reasonable.

Forward Market Electric Prices

111 The Joint Parties argue forward electric market prices should be substituted for those generated internally by AURORA when determining PSE’s power costs. The Joint Parties describe AURORA-derived electricity prices as based on “hypothetical inputs for supply and demand that do not accurately reflect real-world conditions.”⁸⁵ The Joint Parties assert the benefits of using a three-month average of forward market prices include:

- Providing an unbiased estimate of future electricity prices.
- Reflecting PSE’s purchasing strategy with greater accuracy.
- Establishing a uniform approach to estimating both electric and natural gas prices to ensure forecasts are not mismatched.

⁸² ICNU Initial Brief ¶24.

⁸³ *Id.* ¶27.

⁸⁴ Exhibit 269C (Mills) 18:15-19:22.

⁸⁵ ICNU Initial Brief ¶39.

- Eliminating the inefficiency of constantly updating the AURORA data set.⁸⁶

- 112 The Joint Parties contend their recommendation is consistent with Commission precedent and with arguments PSE has made in favor of using forward natural gas prices instead of a fundamentals model for determining gas costs.⁸⁷
- 113 The Commission has relied on, audited, and approved the AURORA model in many proceedings. The Joint Parties provided no analytical support to show that a three-month average Mid-C market forecast predicts actual electricity prices or provides more rigorous results than does the AURORA model.⁸⁸ In addition, while gas costs are an input to the AURORA model, electricity prices are an output. Adjusting the model's results after-the-fact may be fundamentally inconsistent with the model's core logic. On the present record, we simply do not know.
- 114 We do not close the door on the possibility that forward market electric prices might be useful in determining power costs, but additional analysis is required before we could take such a step. As a threshold matter, an analysis is needed to support the statistical validity of using an average of three-months of Mid-C market prices to project power costs. The Company has expressed a willingness to "investigate this idea further."⁸⁹ We accept this offer and expect to hear more about this subject in PSE's next general rate proceeding, if not before.

Determining Extreme Peak Loads

- 115 The Joint Parties argue PSE should be required in future rate filings to calculate the peak requirements temperature based on a historical record of at least thirty years. The Joint Parties assert this approach would ensure the use of a more probable temperature on which to base peaking costs. The Joint Parties contend the Company's current method has a higher probability of including unrealized peaking costs in base rates. The Joint Parties' only recommendation in this

⁸⁶ *Id.* ¶42.

⁸⁷ *Id.* ¶14.

⁸⁸ We note the Commission relied on thorough and detailed statistical analyses when considering whether it should rely on forward gas prices to estimate the fuel costs for gas-fired generation.

⁸⁹ Exhibit 269C (Mills) at 30:10-11.

connection is to adopt this methodology in future rate filings. They do not propose an adjustment to PSE's revenue requirement in this proceeding.

- 116 PSE does not agree that peak temperature should be based on the historical temperature experienced over the same time period used for weather normalization. Nonetheless, the Company says it is open to collaborating with others to examine the appropriate historical period to use when determining design peak temperature.⁹⁰ We encourage such study and support the parties' efforts to improve upon current methods for determining factors that are important to power cost modeling in proceedings such as this one.

ii. Director and Officer Insurance

- 117 The Company allocated the costs of Puget Energy's director and officer ("D&O") insurance premiums among PSE and its subsidiaries using the method approved in Dockets UE-920433, UE-920499 and UE-921262. Staff's argument that PSE failed to establish a reasonable basis for continuing to use the allocation method the Commission approved in 1992 is not persuasive given that Staff offers no analysis to show why the method should be abandoned. Staff developed this methodology in the first place and it has been used for more than a decade, apparently without challenge until now.
- 118 PSE, contrary to what Staff argues, allocated a portion of the test year insurance premiums to Infrastrux, which was sold on May 7, 2006, during the test year.⁹¹ The Company states that Puget Energy's D&O insurance liability did not change as a result of the sale of Infrastrux.⁹²
- 119 Staff's approach and argument suffers from two other significant deficiencies. Staff's proposed adjustment allocates D&O premiums to Infrastrux, yet does not allocate any D&O premiums to non-utility subsidiaries, Puget Western Inc., and Hydro Energy Development Corp., both of which PSE continues to own. Staff does not explain this inconsistency.

⁹⁰ Exhibit 269C (Mills) at 33:18-35:6; PSE Reply Brief ¶122.

⁹¹ PSE Initial Brief ¶125 (citing Exhibit 232C (Karzmar) at 12:18-19.).

⁹² See Exhibit 232C (Karzmar) at 13:19-21.

- 120 Staff's methodology also relies in part on the respective number of employees at PSE and Infrastrux, yet shows no relationship between the number of employees, the risks against which D&O insurance provides financial protection, and D&O insurance premiums. D&O insurance is largely intended to protect directors and officers from shareholder or other suits alleging negligence. We cannot infer, absent any evidence or analysis by Staff, what relationship the number of employees in the respective companies might have to the risk of negligence by a director or officer and, hence, to the allocation of premiums.
- 121 We find PSE's allocation of D&O insurance premiums reasonable and adopt the adjustments shown in Table 8, line 40 and Table 10, line 27 for electric and gas, respectively.

b. Uncontested Adjustments

- 122 We have reviewed the uncontested adjustments summarized in Table 8 and find them reasonable. We adopt these adjustments for purposes of setting rates in this proceeding.

TABLE 8
Restating and Pro Forma Adjustments – Electric

Line No.	Adjustment	NOI	Rate Base
1	Temperature Normalization	\$7,424,007	
2	Revenues & Expenses	218,656,441	
3	Federal Income Tax	4,185,813	
4	Tax Benefit of Pro Forma Interest	(2,916,387)	
5	Conservation	11,852,001	(28,822)
6	Bad Debts	(1,044,352)	
7	Amortization of Deferred Taxes Regulatory Asset	(1,337,206)	
8	Miscellaneous Non-Operating	627	
9	Oregon Prop. Taxes for 3rd AC	(484,484)	
10	Baker Hydro Relicensing Costs	(385,657)	26,254,348
11	Tree Watch Expense	(639,229)	
12	New York Stock Exchange Fees	-	
13	Depreciation on CWIP In-Service	(56,700)	
14	CWIP In-Service Rate Base		3,317,734
15	Property Taxes	383,183	
16	Hopkins Ridge Wind Plant	(9,389,305)	147,154,987

17	Excise Tax & Filing Fee	(384,314)	
18	Montana Energy Tax	8,557	
19	Interest on Customer Deposits	(227,184)	
20	SFAS 133	592,392	
21	Rate Case Expenses	340,717	
22	Property Sales	(18,149)	
23	Property & Liability Ins	(288,833)	
24	Pension Plan	(2,565,770)	
25	Wage Increase	(2,512,047)	
26	Investment Plan	(99,416)	
27	Employee Insurance	(669,622)	
28	Montana Corporation. License Tax	(167,307)	
29	Storm Damage	(197,617)	
30	Regulatory Assets & Liabilities	(2,887,461)	(54,943,645)
31	Wild Horse Plant	(19,715,599)	356,220,868
32	Incentive Pay	690,180	
33	Gen. Office Relocation	(1,644,955)	(3,139,603)
34	Other Amortization	5,065,947	
35	Demand Response Program	0	
36	Depreciation	-	
37	Production Adjustment	787,513	(11,102,293)
38	Total	\$202,355,783	\$463,733,574
Contested adjustments			
39	Power Costs ⁹³	(194,190,197)	
40	D&O Insurance	(13,291)	
Total contested and uncontested			
41	adjustments	\$ 8,152,295	\$ 463,733,574

c. Summary of Electric Revenue Requirement Determination

123 We summarize the results of our electric revenue requirement determinations in Table 9.

⁹³ Exhibit 440, Power Costs (Adjustment 20.03), line 34. Exhibit 4C, PSE NOI, line 4 shows a slightly different amount for power costs, \$194,113,815. The effect of this difference on revenue requirement (Table 9) is slight (*i.e.*, \$17,051,190 instead of \$17,174,242) and the power cost adjustment will change, in any event, when PSE reruns AURORA as required in this Order.

TABLE 9
Electric Revenue Requirement
Docket No. UE-060266

Rate Base	\$ 2,977,316,193
Rate of Return	0.084
NOI Revenue Requirement	250,094,560
Adjusted NOI	\$ 239,433,935
Difference	10,660,625
Conversion Factor	0.6207334
Gross Revenue Requirement Increase (Decrease)	17,174,242

2. Gas

a. Contested Adjustment

i. Director and Officer Insurance

124 This issue is the same as in the case of the electric revenue requirement and our reasons for accepting PSE's allocation of D&O premiums are the same for the gas revenue requirement. The allowed adjustment is shown above in Table 7.

b. Uncontested Adjustments

125 We have reviewed the uncontested adjustments summarized in Table 10 and find them reasonable. We adopt these adjustments for purposes of setting natural gas rates in this proceeding.

TABLE 10
Restating and Pro Forma Adjustments -- Gas

Line No.	Adjustment	NOI	Rate Base
1	Revenue & Expenses, Temperature Normalization	\$13,696,529	
2	Federal Income Tax	490,787	
3	Tax Benefit of Pro Forma Interest	(6,778,498)	
4	Conservation	2,426,926	
5	Bad Debts	(236,343)	
6	Remove Penalties	348	
7	Amortization of Deferred Taxes Regulatory Asset	(923,574)	
8	Depreciation on CWIP In-Service	(55,461)	
9	Rate Base Adjustment CWIP In-Service		2,857,353
10	Property Taxes	469,425	
11	Excise Tax & Filing Fee	389,325	
12	Rate Case Expenses	(78,781)	-
13	Property & Liability Ins	123,942	-
14	Pension Plan	(1,603,511)	-
15	Wage Increase	(1,460,754)	-
16	Investment Plan	(62,124)	-
17	Employee Insurance	(418,486)	-
18	Incentive Pay	431,333	-
19	Interest On Customer Deposits	(131,750)	
20	Property Sales Deferred Gains/Losses	456,881	
21	General Office Relocation	(914,888)	(1,746,177)
22	Low Income Amortization	1,361,790	
28	Everett Delta Pipeline Expansion	48,303	-
29	Spirit Ridge Adjustment	-	-
26	Total	\$7,231,420	\$1,111,176
27	Contested adjustment D&O Insurance	(8,946)	
28	Total contested and uncontested adjustment	7,222,474	1,111,176

c. Summary of Gas Revenue Requirement Determination

126 We summarize the results of our gas revenue requirement determinations in Table 11.

TABLE 11
Gas Revenue Requirement

Rate Base	\$ 1,180,351,743
Rate of Return	0.084
NOI Revenue Requirement	99,149,546
Adjusted NOI	\$ 79,718,936
Difference	19,430,611
Conversion Factor	0.6216003
Gross Revenue Requirement Increase (Decrease)	31,259,011

E. Electric Rate Spread and Rate Design Settlement

127 PSE, Staff, and other parties that took an active interest in the rate spread and rate design issues submitted a proposed Settlement Agreement on July 25, 2006, which they ask the Commission to approve and adopt to resolve all rate spread and rate design issues. The Settlement Agreement is supported by Joint Testimony addressing why the Agreement will result in rates that are just and reasonable, and consistent with established Commission policies. It is unopposed.

128 The parties agree to use PSE's electric cost-of-service study, rate spread, and rate design. According to the settlement, any revenue requirement increase will be allocated among the various customer classes and rate schedules in proportion to the rate spread proposed by PSE. Most electric rate classes are relatively close to parity (*i.e.*, rates recover 97% to 130% of the costs caused by a given customer class) and the proposed rate spread would bring each rate class even closer to parity without causing rate shock.

129 We determine the electric rate spread and rate design proposals presented in the parties' Settlement Agreement are reasonable and should be approved and adopted. The Settlement Agreement is attached to this order as Appendix A and is incorporated into the body of this order by this reference.

F. Gas Rate Spread and Rate Design.

Rate Spread

130 PSE argues its proposed gas rate spread assigns the costs of providing service to the customers who cause the costs to be incurred, improving parity among customer classes while not causing rate shock. PSE states that its rate spread analysis and results consider:

- The results of the Company's recent cost of service (COS) study.
- Each class's contribution to present revenue levels.
- Customer impacts.
- Appropriate price signals to customers.
- Revenue stability.⁹⁴

Seattle Steam supports PSE's rate spread proposal despite acknowledging that it would slightly increase Seattle Steam's bill. According to Seattle Steam, the Company's proposal is superior because it better comports with sound rate-making principles than the alternative proposal advanced jointly by Staff, Public Counsel and NWIGU (Joint Parties) and is otherwise more equitable.⁹⁵

131 Staff argues on behalf of the Joint Parties that their proposal represents a fair, balanced application of both PSE's COS study and the most recent "Commission Basis" COS study, which was approved in a general rate proceeding concluded in the mid-1990's. The Joint Parties, like PSE, contend their proposed gas rate spread minimizes severe customer impacts, but moves all classes toward parity. The Joint Parties emphasize that they consider the results of both cost-of-service studies presented in this case. Thus, the Joint Parties argue, their proposal

⁹⁴ Exhibit 38 at 25-27.

⁹⁵ Seattle Steam Initial Brief ¶2.

represents “a fair and balanced compromise [among themselves] that results in just and reasonable rates, while avoiding contentious litigation of how a proper cost-of-service study should be conducted.”

- 132 The real point of contention between the parties, as the quote above suggests, is that PSE used a method in performing its COS study to which the other parties object. The Joint Parties object principally because what PSE did is different than what the Commission has approved in the past. Specifically, PSE used system design day as the peak cost allocator in its COS study while the so-called Commission Basis approach uses a five-day historic peak allocator. Staff, arguing for the Joint Parties on reply, quotes extensively from the Commission’s 1995 order in which the Commission rejected Avista’s proposal to use design day as a basis for calculating peak usage in favor of “actual use by all classes on real peak days” (*i.e.*, historic peak). Staff argues simply that PSE has not provided evidence to show “why the Commission should diverge from this precedent.”
- 133 The record in this proceeding is not adequate for purposes of evaluating PSE’s use of the design day as a peak allocator in its COS study. We express no opinion on the subject.
- 134 That point of contention aside, we must decide between two rate spread proposals considering the results of the individual COS studies, customer impacts, appropriate price signals, and other factors. Using either COS study, the same rate classes are consistently over-parity or under-parity, with the exception of Schedule 87 and Contracts. The primary difference between the two results is the degree to which the interruptible Schedules 85 and 86 and transportation Schedule 57 are above parity. The Joint Parties’ rate spread allocates more costs and a fixed dollar amount to these schedules based on nothing more than a compromise of the different rate spread proposals discussed by the Joint Parties.⁹⁶ However, there is no rationale developed in the record for assigning a fixed dollar amount, as opposed to a percentage rate increase, to these classes.
- 135 While the evidence and argument on this issue is not developed particularly well by either party, the Company’s case is, on balance, the stronger and more

⁹⁶ Exhibit 581 at 6.

principled approach. We find it reasonable for purposes of determining rates in this proceeding.

Rate Design

- 136 PSE initially proposed to change its current gas rate design to recover modestly more of its fixed costs through customer charges rather than in its volumetric rates. PSE's as-filed rates, for example, proposed to increase the current residential customer charge of \$6.25 to \$8.25. Thus, PSE would recover approximately 24 percent of the fixed costs allocated to the residential class in a demand-type charge.⁹⁷ Later in the proceeding, PSE modified its proposal to allocate approximately 60 percent of its fixed costs to non-volumetric rates resulting in an increase to \$17.00 per month in the customer charge for the residential class.⁹⁸
- 137 PSE argues the current practice of recovering the majority of its fixed costs in volumetric rates fails to recognize the importance of reflecting in rates the nature of fixed costs incurred to provide utility service. In addition, including fixed costs in volumetric rates results in customers under- or over-paying these costs depending on usage patterns, weather, and conservation efforts. According to PSE, recovering more fixed costs in non-volumetric rates will benefit the Company by ensuring recovery of fixed costs despite variations in usage and will benefit customers because there will be greater stability in their monthly bills.
- 138 We find PSE's proposed increase of the Residential Schedule 23 customer charge to \$17.00 represents too much and too rapid change from a customer perspective. However, we agree with PSE that a reasonable balance must be struck in terms of the company's recovery of its fixed costs via fixed rather than volumetric charges. The Joint Parties' do not disagree with this principle, but argue a gradual move in the direction of recovering more fixed costs via non-volumetric rates is the better approach and maintains consistency with general principles concerning rate shock.⁹⁹ This is unquestionably another factor in the balance we must determine.

⁹⁷ PSE Initial Brief ¶136.

⁹⁸ *Id.* (citing Exhibit 186 (Hoff) at 186 7:3-8

⁹⁹ "Rate shock" in the usual connotation is a concern over sharply increasing bills. However, we use the term here, as do the parties in this case, to refer to a dramatic change in a rate component that may or may not result in individual customers having higher bills overall. In general, because utility rates and billing practices are poorly understood, customers may be expected to be upset with a significant change in either the total bill or a bill component that is separately identified on the billing statement.

- 139 We find PSE's original proposal, an increase in the customer charge for this Schedule to \$8.25 strikes the right balance. This will result in the Company recovering about one-fourth of its fixed costs allocated to residential customers via a fixed charge on each customer's bill. This is about eight to ten percent of an average customer's total bill, considering both fixed and variable costs. This seems to us the right balance point for the recovery of fixed costs via the customer charge.
- 140 We reject PSE's proposal to increase the Commercial and Industrial Schedule 31 and 41 customer charges thirty-three percent for the same reason as discussed in connection with the residential rate schedule. Moreover, as the Joint Parties argue, if PSE's motivation for the rate changes in Schedules 31 and 41¹⁰⁰ is to encourage customers to take service under a more appropriate rate schedule, PSE should simply notify those customers rather than by sending an indirect message via a change in rate design. We adopt the Joint Parties' rate design for Schedules 31 and 41, including an increase in the Schedule 31 customer charge to \$17.50, from the current \$15.00, and an increase in the Schedule 41 customer charge to \$80.00 from the current \$70.00.
- 141 PSE's proposals regarding Transportation and Interruptible Schedules 57 and 87 are reasonable. We approve PSE proposed increase in the Schedule 57 balancing charge to .000140 cents per therm. We also approve PSE's proposal to maintain the current customer charge for each class, \$800 and \$500 respectively¹⁰¹. We determine that PSE's rate design for these schedules should be adopted.
- 142 In sum, we approve the rate design proposed by the Joint Parties for all contested rate schedules except Schedules 23, 57 and 87, thus taking a measured step in the direction of allowing PSE to recover more of its fixed costs in non-volumetric rates while avoiding rate shock to any customer class.¹⁰² We accept PSE's

¹⁰⁰ PSE also proposed to increase the current demand charge from \$.50 to \$1.00, or 100 percent. Exhibit 38 at 28. We find more reasonable the Joint Parties proposed 40 percent increase in the demand charge to \$.70. Exhibit 581 at 11.

¹⁰¹ The Joint Parties' propose a significant increase to the Interruptible Schedule 87 customer charge.

¹⁰² No one proposes to change the customer charges under Schedules 85 and 86. However, we accept the Joint Parties proposal to increase the volumetric rate for these Schedules. We also approve the Joint Parties recommendation that a procurement charge of 0.65 cents/therm be used for both schedules. Finally, we approve the Joint Parties' proposal to increase the volumetric rate for the first 25,000 therms for Schedule

originally proposed change in the customer charge to Residential Schedule 23. from 6.25 to 8.25. Finally, we approve the uncontested rate design for Commercial and Interruptible Schedules 36, and 51, and Rental Schedules 71, 72, and 74.

- 143 The Joint Parties propose, and PSE agrees that the Company's current rate schedules should be reviewed before the next general rate case filing to consider how schedules could be combined or separated to better reflect similar types of usage and cost causation. We encourage the parties to undertake such a review prior to PSE's next general rate filing.

G. Low Income Assistance Programs Settlement

- 144 The parties that proposed settlement of the electric rate spread and rate design issues also resolved among themselves issues concerning PSE's low income assistance programs. The parties included in the electric rate spread and rate design settlement filed on July 25, 2006, and attached to this Order as Appendix A, provisions that address these issues. Their proposal is uncontested, appears reasonable and is supported by the record. We find it will serve the public interest to approve and adopt the settlement to resolve all issues concerning the Company's low income assistance programs.

H. Electric Energy Efficiency Incentive

- 145 PSE asks the Commission to authorize a performance incentive plan based on the energy savings performance of the Company's electricity conservation programs. The Company's initial proposal was for an incentive based on a percentage of its expenditures under the conservation programs supported by its current conservation tariff rider. Under the as-filed proposal, PSE would earn an incentive payment if its conservation programs achieved conservation savings in any year in excess of a target set by the Conservation Resource Advisory Group (CRAG). The Company's initial proposal was for a five-year program.
- 146 Staff, Public Counsel and NWECA, in their respective response cases, all supported a conservation performance incentive program in principle, but not the Company's

85 and, for Schedule 86, the first 1,000 therms. For a comparison of PSE and the Joint Parties' proposals of Schedules 85 and 86, see Exhibit 581at 13.

proposal. Each of these parties proposed a program based on an annual performance target, two-part incentives, penalties for failure to perform, a dead band between the penalty threshold and the incentive threshold and a set of 12 program design and implementation principles. While the three parties agreed on the 12 design principles, they disagreed on the annual target for 2007, the penalty and incentive thresholds, the dead band and the level of incentives and penalties.

147 FEA opposed any incentive program, arguing that ratepayers should only pay prudently incurred costs for conservation and no more. According to FEA, the costs associated with the energy efficiency program should be treated no differently than the costs associated with installation of a supply side option.

148 PSE modified its proposal on rebuttal to fit the basic framework of the programs proposed by Staff, Public Counsel and NWECA. PSE, however, did not agree with all aspects of any of these parties' proposed designs and expressly objected to four of the design principles. PSE argues the Commission should not adopt the following design principals urged by Staff, Public Counsel and NWECA:

- The average measured life for the conservation portfolio should be no less than nine years.
- Measures undertaken by the Northwest Energy Efficiencies Alliance (NEEA) to whom the Company provides fund can only be counted toward the performance target in the year in which funding occurs.
- A new evaluation committee should be formed to verify and evaluate the performance of the Company's conservation measures and programs.
- The program should be a pilot for three years only, with evaluation to occur before the program is continued.

149 Table 12 depicts the 2007 target level, the dead band, and the penalty and incentive thresholds proposed by each party.

TABLE 12

	2007 Target aMW	Penalty Threshold	Incentive Threshold
PSE	16.5	95 percent	105 percent
Staff	18.3	90 percent	100 percent
Public Counsel	20.0	80 percent	90 percent
NWECA	16.5	95 percent	105 percent

Tables 13 and 14 show the incentive and penalty payment levels proposed by each party. There are two components to the incentive payment:

- Volume of savings at \$/MWh of first-year savings.
- Shared Net Savings Incentive – a percentage of the difference between the cost of saved MWhs and the value of saved MWhs (\$1.80 per MWh based on an avoided cost of \$5.90/MWh – \$4.10/MWh average cost of the conservation). This component is included to encourage cost-efficiency in program management and effectiveness.

The tables demonstrate some key differences among the proposals.

- PSE and NWECA do not assess a penalty until performance falls to less than 95% of the target.
- Staff is the only party to calculate incentives and penalties based on the difference between “actual” and the target (except right at the target). The other parties apply penalties and incentives to total MWhs.
- NWECA proposes the largest penalties.
- Public Counsel calculates an incentive before the target is achieved.

TABLE 13

	PSE			Staff¹⁰³	
% of Target Ranges	\$/MWH	Net (%)	% of Target Ranges	\$/MWH	Net (%)
>150%	20	50			
140% - <150%	20	35			
130%- <140%	20	25			
120%- <130%	20	15	140%-< 150%	20	100
115%- <120%	20	10	130%- <140%	20	80
110%- <115%	10	5	120% - <130%	20	40
105%- <110%	4	0	110%- <120%	20	20
100%- <105%	0	0	100%- <110%	20	10
Target = 16.5 aMW			Target = 18.3 aMW	10	5
95% - <100%	0		90%- <100%	0	

¹⁰³ Staff’s mechanism calculates an incentive for all MWh saved if the target is achieved and incentives for higher levels of performance based on the increment of savings above the target.

90% - <95%	(100)		80%-<90%	(75)	
80% - <90%	(110)		70%-<80%	(80)	
70% - <80%	(110)		60%-<70%	(85)	
60% - <70%	(110)		50%-<60%	(90)	
50% - <60%	(110)		<50%	(95)	
<50%	(110)				

TABLE 14

	Public Counsel			NWEC¹⁰⁴	
% of Target Ranges	\$/MWH	Net (%)	% of Target Ranges	\$/MWH	Net (%)
			> 150%	20	40
			140%- <150%	20	33
			130%- <140%	20	25
			120%- <130%	20	15
>120%	16	16	115%- <120%	15	5
110%- <120%	16	14	110%- <115%	10	0
105%- <110%	16	12	105%- <110%	5	0
100%- <105%	14	10	100%- <105%	0	0
Target = 20 aMW			Target = 16.5 aMW		
95% - <100%	+12	0	95% - < 100%	0	0
90% - <95%	+10	0	< 95%	(171)	
80% - <90%	0	0		(171)	
70% - <80%	(40)			(171)	
60% - <70%	(60)			(171)	
50% - <50%	(80)			(171)	
<50%	(115)				

150 Staff argues persuasively that it is appropriate to implement an incentive program for conservation on a pilot basis. According to Staff an incentive mechanism reflects sound public policy because:¹⁰⁵

- The legislative finding in RCW 80.28.024 states, in relevant part, “The legislature finds and declares that the potential for meeting future energy

¹⁰⁴ NWEC proposes a penalty of \$1.5 million per aMW of shortfall below 95% of the target. \$1.5 million per aMW = \$171/mwh.

¹⁰⁵ Staff Initial Brief ¶¶124-131.

needs through conservation measures . . . may not be realized without incentives to public and private utilities. . .”

- The Commission’s policy encourages energy conservation (WAC 480-100-238, the Integrated Resource Plan Rule).
- PSE’s energy conservation expenditures do not earn a return, as owned supply-side resources do, and may result in lost revenues.
- PSE is subject to penalties for failing to achieve conservation targets, but is not rewarded for meeting or achieving those targets.

151 We observe, in addition, that RCW 80.28.260 states in relevant part:

(3) The commission shall consider and may adopt other policies to protect a company from a reduction of short-term earnings that may be a direct result of utility programs to increase the efficiency of energy use. These policies may include allowing a periodic rate adjustment for investments in end use efficiency or allowing changes in price structure designed to produce additional new revenue.

152 FEA’s objection that conservation resources do not deserve an incentive because installations of supply-side options do not receive any additional payment misses the point that supply-side options receive a return on investment. As currently funded, conservation does not earn a return. However, conservation expenditures can be included in rate base as provided in RCW 80.28.260, which states in relevant part:

(2) The commission shall consider and may adopt a policy allowing an incentive rate of return on investment in additional programs to improve the efficiency of energy end use or other incentive policies to encourage utility investment in such programs.

153 We conclude that state law and policy clearly support the use of financial incentives to promote a broad array of conservation measures. All of the proposed electric conservation programs provide such incentives and encourage through their design Company efforts to achieve as much cost-effective conservation as possible.

- 154 After carefully reviewing all of the proposals, we find the Staff design is the most balanced and reasonable. It provides a clear and consistent pattern of rewards for performance and it preserves the current threshold of 16.5 aMW minimum performance for penalty avoidance. By initiating incentive payments when PSE achieves the 18.3 aMW target, we effectively agree with PSE that “[i]t is better policy and more understandable to stakeholders to set a reasonably achievable target and then incent the Company to reach beyond the target”.
- 155 With regard to the disputed program design principles, we find a nine-year average measure life is appropriate. The Company’s program already achieves this without excluding individual initiatives that have lives less than nine years. We emphasize that the criterion is that the average measure life of the program be nine years, not that every program or project have a life of nine years.
- 156 We also agree that the pilot program should be three years long commencing in January 2007 and running through December 2009. The three-year time-frame will permit whatever transition to the requirements of I-937 will be necessary in 2010.
- 157 We also agree with the principle that savings counted in any given year should be directly tied to actions of the Company in that year. However, it is widely recognized that some conservation programs are inherently multi-year in nature posing challenges to measurement in one year. NEEA, in particular, aims many of its efforts at multi-year market transformation. We would not want to see the Company’s support for these beneficial efforts discouraged by tying credit for conservation efforts strictly to the Company’s funding of NEEA programs in a given year. At the same time, credit for multi-year conservation efforts should not be double-counted. Consequently, we direct the Company and Staff, in consultation with the CRAG and NEEA, as appropriate, to develop criteria for counting annual incremental savings from PSE’s participation in NEEA efforts that reflect the Company’s participation in multi-year efforts while protecting against any double-counting of savings.
- 158 Finally, we decline to order the establishment of a new evaluation group. Evaluation is important in terms of performance measurement and to inform the design of future programs. This is an important function of the CRAG. The CRAG and Staff can draw on the evaluation and studies undertaken by the

Regional Technical Forum, which is also focused on studying performance and program design issues. We expect the results of this pilot program to be professionally evaluated in a cost-effective manner determined by Staff and PSE, with advice from the CRAG.

I. Weather Normalization Methodology

- 159 Weather normalization is a statistical method used to estimate what customer loads would have been in the test-year if normal weather conditions, measured in terms of temperature, had prevailed. In this case, the Company uses a weather normalization procedure that differs from the method it has used in prior cases. In particular, past weather normalization calculations employed temperature data adjusted to represent a single balance point temperature.¹⁰⁶ In this case, the Company models weather sensitive load using the conventional balance point and additional, lower balance points designed to reflect that buildings are better insulated today than they were in the past.
- 160 Staff does not object to the use of the proposed, multiple-balance-point model in this case, but urges the Commission to order the Company to perform load research analysis to prove the accuracy of its weather normalization procedure.
- 161 PSE's methodology appears to be highly reliable, explaining 97 percent of variation in historical aggregate customer load. Moreover, PSE's approach yields a revenue requirement that is \$1.4 million lower than it would have been under the prior methodology.
- 162 It is always possible to improve statistical precision, but the question is to what purpose and at what cost. Staff does not dispute the results PSE achieved for purposes of setting rates. PSE estimates it would cost the Company \$3.5 million to fund the study Staff proposes. PSE argues reasonably that if the Commission

¹⁰⁶ Balance point is the external temperature at which buildings require no auxiliary heating or cooling to maintain the desired internal temperature (the actual indoor temperature will be higher due to retained heat from the occupants, lights, electronic equipment and so forth). Conventionally, 65° F is the balance point temperature used to calculate heating and cooling degree-days. Heating and cooling degree days are calculated over a period of time (typically a year) by adding up the differences between each day's mean daily temperature and the balance point temperature. Thus, for example, three successive winter days with average temperatures of 50°F, 47°F and 52°F include a total of 46 heating degree days (HDD).

orders it to perform the study urged by Staff, it should also approve an additional \$3.5 million in revenue requirement to pay for the study.

163 We express no opinion about the finer points of the approach PSE used in its weather normalization analysis, but we are satisfied both by its apparent high level of precision and by Staff's acquiescence to its results that it has proven adequate in this instance to capture "normal" – a concept that is imprecise in any event.¹⁰⁷ We expect that PSE will continue to take advantage of opportunities to improve weather normalization methodology and data, relying on advances such as PSE's widespread use of "smart meters." We will not, however, order PSE to undertake an expensive study that might be interesting on an academic level but is unnecessary to produce results acceptable for purposes of setting rates.

J. Prudence of Resource Acquisitions

164 The Commission evaluates the prudence of resource acquisitions by asking what "a reasonable board of directors and company management [would] have decided given what they knew or reasonably should have known to be true at the time they made a decision."¹⁰⁸ This test applies both to the question of need and the appropriateness of the expenditures.

165 PSE's direct case includes substantial competent evidence¹⁰⁹ showing the need and appropriateness of the Company's expenditures incurred in connection with:

- Acquisition of the Wild Horse wind farm.
- The 20-year purchased power agreement between PSE and OrSumas, LLC.
- Relicensing of the Baker River Hydroelectric Project.
- The 20-year purchased power agreement and related transmission agreement between PSE and Public Utility District No. 1 of Chelan

¹⁰⁷ We note, for example, the problems inherent in the underlying concept of heating/cooling degree day. Heat requirement is not linear with temperature. Heavily insulated modern buildings have a lower balance point than do older buildings with less insulation. Solar gain reduces the need for heating on sunny days (but not cloudy days), and wind increases it (by an amount that depends on how tightly the building is constructed). People also differ in their opinions about what constitutes a comfortable indoor temperature and, thus, place inconsistent demands on HVAC systems at given outdoor temperatures.

¹⁰⁸ *WUTC v. Puget Sound Power & Light Co.*, Cause No. U-83-54, Fourth Supp. Order at 32 (1984).

¹⁰⁹ See, e.g., Garratt, Exhibit 153HC 3-27; Molander, Exhibit 291HC, 2-17; Olin, Exhibit 351HC 6-29.

County, Washington (including recovery of interest at the net of tax rate of return).

- Acquisition of long term gas pipeline capacity from Duke Energy Trading and Marketing.

No party challenged the prudence of these expenditures. We determine that PSE's acquisition of each of the above-listed resources is prudent and find the associated costs are reasonable for recovery in rates.

FINDINGS OF FACT

166 Having discussed above in detail the evidence received in this proceeding concerning all material matters, and having stated findings and conclusions upon issues in dispute among the parties and the reasons therefore, the Commission now makes and enters the following summary of those facts, incorporating by reference pertinent portions of the preceding detailed findings:

167 (1) The Washington Utilities and Transportation Commission is an agency of the State of Washington, vested by statute with authority to regulate rates, rules, regulations, practices, and accounts of public service companies, including gas and electrical companies.

168 (2) Puget Sound Energy, Inc., (PSE) is a "public service company," a "gas company," and an "electrical company" as those terms are defined in RCW 80.04.010 and as those terms otherwise are used in Title 80 RCW. PSE is engaged in Washington State in the business of supplying utility services and commodities to the public for compensation.

169 (3) PSE has not carried its burden to show its proposed modifications to the dead band and cost sharing features of its current power cost adjustment mechanism (PCA) are in the public interest.

170 (4) The following investments by PSE were prudent and were made at reasonable costs:

- Acquisition of the Wild Horse wind farm.

- The 20-year purchased power agreement between PSE and OrSumas, LLC.
- Relicensing of the Baker River Hydroelectric Project.
- The 20-year purchased power agreement and related transmission agreement between PSE and Public Utility District No. 1 of Chelan County, Washington (including recovery of interest at the net of tax rate of return).
- Acquisition of long term gas pipeline capacity from Duke Energy Trading and Marketing.

- 171 (5) PSE, having revised its initial proposal for increased rates during the course of this proceeding, did not show the rates proposed by tariff revisions filed on February 15, 2006, and suspended by prior Commission order, to be fair, just, or reasonable.
- 172 (6) PSE has demonstrated by substantial competent evidence that its current rates are insufficient to yield reasonable compensation for the electric and gas services it provides in Washington.
- 173 (7) The record in this proceeding supports a capital structure and costs of capital, which together produce an overall rate of return of 8.40%, as set forth in the body of this Order in Table 5.
- 174 (8) The Commission's resolution of the disputed issues in this proceeding, coupled with its determination that certain uncontested adjustments are reasonable, result in finding that PSE's natural gas revenue deficiency is \$31,259,011 and its electric revenue deficiency is \$17,174,242.
- 175 (9) PSE requires relief with respect to the rates it charges for electric service and gas service provided in Washington State so that it can recover its natural gas service and electric service revenue deficiencies.
- 176 (10) The terms of the multi-party settlement concerning electric rate spread and rate design, and low-income energy assistance, attached to this Order as Appendix A and incorporated by this reference, are consistent with the public interest.

177 (11) The rates, terms, and conditions of service that result from this Order are
fair, just, reasonable, and sufficient.

178 (12) The rates, terms, and conditions of service that result from this Order are
neither unduly preferential nor discriminatory.

CONCLUSIONS OF LAW

179 Having discussed above all matters material to this decision, and having stated
detailed findings, conclusions, and the reasons therefore, the Commission now
makes the following summary conclusions of law, incorporating by reference
pertinent portions of the preceding detailed conclusions:

180 (1) The Washington Utilities and Transportation Commission has jurisdiction
over the subject matter of, and parties to, these proceedings. *Title 80 RCW.*

181 (2) The rates proposed by tariff revisions filed by PSE on February 15, 2006,
and suspended by prior Commission order, were not shown to be fair, just
or reasonable and should be rejected. *RCW 80.28.010.*

182 (3) PSE's existing rates for natural gas service and electric service provided in
Washington State are insufficient to yield reasonable compensation for the
service rendered. *RCW 80.28.010; RCW 80.28.020.*

183 (4) PSE requires relief with respect to the rates it charges for natural gas
service and electric service provided in Washington State. *RCW 80.01.040;*
RCW 80.28.060.

184 (5) The Commission must determine the fair, just, reasonable, and sufficient
rates to be observed and in force under PSE's tariffs that govern its rates,
terms, and conditions of service for providing natural gas and electricity to
customers in Washington State. *RCW 80.28.020.*

185 (6) The costs of PSE's investments found on the record in this proceeding to
have been prudently made and reasonable should be allowed for recovery in
rates.

- 186 (7) PSE should have the opportunity to earn an overall rate of return of 8.40% based on the capital structure and costs of capital set forth in the body of this Order, including a return on equity of 10.40% on an equity share of 44.00%.
- 187 (8) PSE should be authorized and required to make a compliance filing to recover its revenue deficiency of \$31,259,011 for natural gas service and \$17,174,242 for electric service. *WAC 480-07-880(1)*.
- 188 (9) The multi-party settlement concerning electric rate spread and rate design, and low-income energy assistance, attached to this Order as Appendix A and incorporated by prior reference, should be approved and adopted.
- 189 (10) The rates, terms, and conditions of service that will result from this Order are fair, just, reasonable, and sufficient. *RCW 80.28.010; RCW 80.28.020*.
- 190 (11) The rates, terms, and conditions of service that will result from this Order are neither unduly preferential nor discriminatory. *RCW 80.28.020*.
- 191 (12) The Commission Secretary should be authorized to accept by letter, with copies to all parties to this proceeding, a filing that complies with the requirements of this Order. *WAC 480-07-170; WAC 480-07-880*.
- 192 (13) The Commission should retain jurisdiction over the subject matters and the parties to this proceeding to effectuate the terms of this Order. *Title 80 RCW*.

ORDER

THE COMMISSION ORDERS THAT:

- 193 (1) The proposed tariff revisions PSE filed on February 15, 2006, which were suspended by prior Commission order, are rejected.
- 194 (2) The multi-party settlement concerning electric rate spread and rate design, and low-income energy assistance, attached as Appendix A and incorporated into this Order by prior reference, is approved and adopted.

- 195 (3) PSE is authorized and required to file tariff sheets following the effective
date of this Order that are necessary and sufficient to effectuate its terms.
The required tariff sheets must be filed at least three business days prior to
their stated effective date. .
- 196 (4) Its prior orders approving and otherwise concerning the Company's PCA
mechanism are modified to the extent necessary to effectuate the terms of
this Final Order.
- 197 (5) The Commission Secretary is authorized to accept by letter, with copies to
all parties to this proceeding, a filing that complies with the requirements of
this Final Order.
- 198 (6) The Commission retains jurisdiction to effectuate the terms of this Final
Order.

Dated at Olympia, Washington, and effective January 5, 2007.

WASHINGTON STATE UTILITIES AND TRANSPORTATION COMMISSION

MARK H. SIDRAN, Chairman

PATRICK J. OSHIE, Commissioner

PHILIP B. JONES, Commissioner

NOTICE TO PARTIES: This is a Commission Final Order. In addition to judicial review, administrative relief may be available through a petition for reconsideration, filed within 10 days of the service of this order pursuant to RCW 34.05.470 and WAC 480-07-850, or a petition for rehearing pursuant to RCW 80.04.200 and WAC 480-07-870.

APPENDIX A

**Partial Settlement Agreement re: Electric Rate Spread, Rate Design and Low
Income Energy Assistance**

APPENDIX B

Revenue Requirement Stipulation

GLOSSARY

BEFORE THE WASHINGTON UTILITIES AND TRANSPORTATION COMMISSION

WASHINGTON UTILITIES AND
TRANSPORTATION
COMMISSION,

Complainant,

v.

PUGET SOUND ENERGY, INC.

Respondent.

DOCKET NO. UE-060266

DOCKET NO. UG-060267

**OPENING BRIEF
OF PUBLIC COUNSEL**

OCTOBER 31, 2006

I. INTRODUCTION

1. Public Counsel's brief will focus on three major areas of this case: decoupling, PSE's depreciation tracker, and PSE's proposed changes to its power cost adjustment mechanism (PCA). On each of these issues, Public Counsel explains why it opposes the Company's proposals and asks the Commission to reject them. For decoupling and the PCA, this brief provides alternative proposals for the Commission's consideration. As this brief will explain, each of PSE's three proposals has something in common. Each of them shifts significant financial risk to PSE ratepayers. PSE's case makes no provision for compensating customers, through a reduced cost of capital for other mechanism, for this shift.
2. While there is never a justification for unreasonable and unfair rate proposals, PSE's requests in this case should receive even more careful scrutiny in this era of almost continuous upward movement in rates. As the comments from the public in the record highlight, energy costs are imposing increasingly severe hardships on customers. While PSE is entitled to the opportunity to earn a reasonable rate of return and recover prudently incurred costs, the three proposals mentioned above go beyond this. This case provides the Commission an opportunity to protect consumers from the unnecessary rate increases that would result from adoption of these unbalanced new proposals.
3. During the course of the case, Public Counsel and other parties have also had productive discussions that have led to resolution on several issues. All parties have reached agreement with PSE on electric rate spread and rate design. Public Counsel, Commission Staff and other intervenors reached multi-party settlements on gas rate spread and design, PCA, and power costs. The brief addresses these agreements as well.

4. Another important area of agreement between Public Counsel, PSE, Commission Staff, and NWECA is that the Commission should approve an incentive mechanism for PSE's electric energy efficiency programs. While the parties propose different designs for the mechanism, all agree that adoption of such a mechanism is in the public interest.

II. PUBLIC COMMENT

A. The Renton Public Hearing.

5. A public hearing was held in Renton on June 29, 2006. Eight witnesses addressed the Commission at the Renton hearing, six against the proposed rate increases and two for the cause of renewable energy. Attendees included senior citizens, environmental organizations, and homeowner association representatives. Diana Chan of Lynnwood testified:

As a senior member of society and on a very limited income, fixed income, by the way, any increase raises a financial difficulty in the area of health, safety, medical expenses and plain survival. Living on a fixed income of SSI and a small disability, I'm also required to participate in care and expenses of my husband...who suffered a stroke two years ago, as well as pay for my own medical expenses, food for survival, and pay for all the utilities and expenses on a house...Do we need to decide between, one, disconnect the gas furnace; two, medical needs; three, food and survival; four care of a loved one in an adult home? ¹

6. John Ruegsegger testified for the Lake Meridian Ridge condominium complex in Kent:

...[T]he rate increases have been rather steady. PSE wants another increase in funds from their customers, who are put in the position of being the unlimited resource every time PSE wants more, and the reasons are endless. In October '04, PSE increased the low-income assistance program, and I do not have things against assisting people who cannot afford that, so I would not object so much to that. But in March '05, they had another rate increase. In April '05, there was another increase. In November '05, there was another increase. And in April '06, another increase took effect... [a]fter those increases, you're asking for a 17 percent increase in the electrical customer charge, a 32 percent increase in the gas customer charge, and an increase to the rate of return on equity, add a surcharge tracker for depreciation, add a decoupling mechanism to

¹ Tr. 52:22-53:2, Tr. 53:10-12.

make natural gas revenue separate from gas sales and again expand the low-income assistance program. And all this PSE says will increase residential electric rates by less than 12 percent a month. That's every month for those of us who have to pay...Please consider that we ratepayers do not have an endless supply of money. We're going broke...We don't get all these increases in our salaries. Sometimes, for years at a time, we don't get increases. We simply cannot afford this upward spiral for more and more and more.²

B. Written Public Comments.

7. Exhibit No. 1 consists of letters, e-mails, and other written materials submitted by the public to the Commission and to Public Counsel to provide comment on this case. The exhibit includes a total of 341 written comments, of these 327 oppose and/or express serious concern over the requested rate increase; the remaining 14 neither oppose nor support the request. M. Lynn Kole of Bellingham wrote, opposing the increase:

I have never written a comment before, but it just seems like every time they ask for an increase they get it. I think this rate increase is too large. I'm a single person making minimum wage and everything just keeps going up. My property taxes, natural gas, and now electric. I would like to stay in my home. I have lived here for 30 years and raised my kids in this house, but I just wonder how long I can stay here. I don't have medical insurance and I try to live as cheaply as I can, but I oppose this big of an increase in the electric rates.³

8. Mr. Geoffrey Harris also expressed concern about possible economic hardships for ratepayers, writing, "Regardless of what is printed in the national media bout an expanding economy, most of us are really living from paycheck to paycheck with no relief in sight."⁴ Edward and Gail Debraie of Kent, who are on social security wrote, "My husband calculated the impact of this proposed rate increase on this years Social Security increase. It was \$188.58. This is three months of our combined SS increase this year."⁵

² Tr. 49:2-25, 50:15-21.

³ Exh. No. 1, p. 275.

⁴ Exh. No. 1, p. 181.

⁵ Exh. No. 1, p. 173.

9. Thomas and Brenda Fischer expressed uncertainty regarding customer charges and billing, writing in an email, “Just what exactly is the “customer charge” for? It seems to us that their bills are fraught with charges that no one seems to understand.”⁶

10. Ms. Susan Hirz of University Place wrote:

I am opposed to the fact that a significant portion of the increase for residential natural gas customers would be in the form of a 32% increase in the monthly customer charge instead of an increase tied primarily to gas consumption. I am also suspicious of the proposed “decoupling” mechanism...I think a much fairer proposal would be to introduce a tiered rate structure in which customers who consumed more than a certain amount each month would pay a higher price per therm...In January of this year I spent over \$1300 to add insulation to my home through a Puget Sound Energy pilot program and at the recommendation of a PSE-affiliated insulation contractor. Over the first four months since the installation, I saved a total of 18.5 therms compared to the same period one year ago (with useage habits unchanged from a year ago). This corresponds to a savings of \$20.89 (an average \$5.22/month) at current natural gas rates. Clearly it is unlikely I will ever recoup my financial investment. It adds insult to injury that PSE now wants to increase the fixed monthly customer charge and further decouple their revenue from sales volume...I would like to see any current and future customer rate increases linked entirely to level of energy consumption.⁷

III. DECOUPLING

A. Overview.

11. In this case, as in other settings where it is proposed, the decoupling cause is clothed in the banner of conservation. At first blush, this seems a compelling argument. The goal of energy efficiency is a worthy one, supported and indeed advanced by industry, consumer

⁶ Exh. No. 1, p. 356.

⁷ Exh. No. 1, pp. 91-92.

12. advocates, customers, environmentalists, and regulators. It seems self-evident that implementing energy efficiency is detrimental to a utility company's financial picture. The identified problem and the proposed solution seem logical. So why should this Commission not hasten to adopt this attractive "fix" to an apparent problem? The purpose of Public Counsel's evidence and briefing in this case is to suggest that, however attractive on the surface, the decoupling proposals in this case should be examined carefully. When they are, we believe the Commission will find that decoupling is not the answer to concerns regarding utilities motivation to pursue energy efficiency. In its evaluation of the decoupling proposals in this case, the Commission should seek answers to at least the following serious questions:

- What is the actual amount of margin lost due to PSE's own energy efficiency efforts and the significance of the financial impact on the company?
- What proportion of declining customer use is attributable to company conservation efforts, as compared to other causes not related to company actions?
- What rate and revenue burden will fall on consumers and is it properly proportioned to the "lost margin" from PSE-sponsored conservation programs?
- What is PSE's track record on energy efficiency?
- Are there reasons why PSE has pursued energy efficiency without a decoupling mechanism and can it be expected to do so in the future?
- What specific additional energy efficiency programs will PSE customers see if decoupling is adopted?
- Are customers compensated for their increased risk and the reduction of risk to shareholders?
- Are there alternatives to decoupling?

13. PSE, Staff, and NWECA do not devote much time, if any, to an objective examination of these questions. They simply accept the premise that decoupling makes sense, and devote their efforts to designing their preferred mechanism. The purpose of this brief is to help the Commission find the answers to the above questions in the record of this case and to get behind the rhetorical claims to evaluate the real impact and effectiveness of decoupling for PSE's customers. Public Counsel believes that when that analysis is done, the decoupling proposals will be seen as a flawed, unnecessary, overbroad, and expensive experiment that will hurt ratepayers and make little or no contribution to conservation. Public Counsel also believes that if the Commission wishes to provide financial incentives to PSE to pursue natural gas conservation that a simpler, more affordable, and better targeted mechanism is readily at hand.

B. PSE's Decoupling Proposal is Primarily Designed to Guarantee Revenue Levels and Shift Risk, Not Provide an Incentive for Conservation.

1. Decoupling is advertised as a mechanism to encourage energy efficiency.

14. One of the consistent claims of decoupling advocates is that decoupling is critical to ensure that regulated utilities can pursue the goal of energy efficiency. This case is no different. PSE witness Ron Amen testified that current ratemaking "creates a *significant* financial disincentive for it to aggressively promote energy efficiency for its customers."⁸ Mr. Amen asserts that PSE's decoupling proposal, the Gas Revenue Normalization Adjustment (GRNA) "will enable PSE to solve the dilemma it faces as it promotes energy efficiency programs for its customers, that is, for every therm saved due to energy conservation, PSE fails to recover another unit of its authorized distribution margin."⁹

⁸ Exh. No. 21, p. 28:2-3 (Amen) (emphasis added).

⁹ *Id.*, p. 26:16-19.

15. NWEC’s support for decoupling makes the same assertions.¹⁰ Commission Staff echoes this point. In her direct testimony, Staff witness Joelle Steward offers a common formulation of the decoupling argument:

One of the primary goals for a decoupling mechanism is to remove a utility’s disincentive to promote energy efficiency. Under current rate structures, revenues are largely generated through volumetric charges; therefore, reducing energy use may result in lower profits for the utility, and may compromise the ability of the utility to recover its fixed costs. A decoupling mechanism, which restores to the utility the margins “lost” due to customer efficiency, would then allow the utility to pursue energy efficiency without losing profits and make it more likely that it would recover its fixed costs.¹¹

While Staff supports a different mechanism than PSE’s GRNA, Ms. Steward recommends that her “partial decoupling” mechanism be adopted as a three-year pilot, because it “will remove PSE’s disincentive to promote energy conservation by restoring lost margin due to customers’ non-weather related changes in usage.”¹²

2. Many factors other than PSE energy efficiency programs cause declining use.

16. PSE-sponsored energy efficiency programs are only one factor causing declining use of gas on a per-customer basis. Many other factors also play a major role. Many have more effect than Company-sponsored efficiency. As discussed in more detail later in the brief, the non-company factors, in the aggregate, have a much larger impact than company actions.

17. The table below outlines individually significant drivers of gas sales volume changes and indicates whether changes in gas usage caused by that variable would be subject to rate recovery through the decoupling tariff proposal of each of the party.

¹⁰ Exh. No. 502, p.5:10-21 (Weiss).

¹¹ Exh. No. p. 561, 5:20–6:6 (Steward).

¹² Exh. No. p. 561, 8:5-6. (Steward).

Table 1: Rate Recovery of Sales Volume Drivers

SALES VOLUME DRIVER	GENERAL ONGOING SALES VOLUME IMPACT	PSE Decoupling Proposal	NWEC Decoupling Proposal	Staff Decoupling Proposal
Number of Customers	Increasing	No	No	No
Weather Abnormality	Variable	Yes	Yes	No
Price Elasticity	Decreasing	Yes	Yes	Yes
Replacement of Inefficient Old Appliances / Furnaces	Decreasing	Yes	Yes	Yes
Construction of Buildings – Improved Building Codes	Decreasing	Yes	Yes	Yes
Customer Financed Conservation Investments	Decreasing	Yes	Yes	Yes
Utility Sponsored Conservation Investments	Decreasing	Yes	Yes	Yes

Source: Exh. No. 509, p. 5:9 (Brosch).

18. As the table indicates, PSE's GRNA proposal and the NWEC proposal both allow rate recovery for all listed factors causing variability (weather) or decline in revenues. Staff's proposal excludes recovery for weather-related variability, but otherwise allows recovery for all factors causing decline.
19. Most of the drivers of declining use per customer are beyond the control of the Company management and not influenced by ratemaking procedures or incentives. There will be price elasticity effects whenever higher prices, for any reason, cause customers to reduce use. Appliance manufacturers must comply with federal efficiency standards designed to produce energy savings. Improved building codes for new homes, and remodeling for existing homes

under those codes, are intended to reduce use and likely will do so. All of these trends are translated by decoupling into rate increases for customers. Even when ratepayers use their own money to conserve energy, with decoupling in place their efforts are “rewarded” by energy price increases to insulate the utility from sales losses.

20. The American Gas Association reports provided by PSE in response to Staff discovery, put the claims of declining use per customer in context.¹³ The primary causes of declining use cited by the study include housing characteristics, demographics, appliance efficiency gains, and reduced appliance saturation.¹⁴ Other factors identified but not quantified due to lack of data included water conservation, economic influences, environmental regulations, the popularity of gas hearth products, and the rise in seasonal homes.¹⁵ Interestingly, Company-sponsored conservation was not identified as a separate contributing factor.

21. The studies indicate that gas use by residential customers has been declining for decades, since at least 1980.¹⁶ The existence of a historic and long term decline in use is relevant for several reasons. First, its beginning predates much of today’s company sponsored energy efficiency efforts confirming that many other factors are at work. Second, the fact that companies have continued to sponsor energy efficiency in an era of declining use casts doubt both on the amount of negative financial impact caused by company sponsored programs and on the alleged disincentive to invest in such programs. Third, evidence of long term decline shows that traditional ratemaking can adequately address company financial needs even in the face of declining use per customer. Fourth, the projections that this trend will continue mean that

¹³ Exh. No. 56, pp. 3-19, Patterns of Residential Natural Gas Consumption, 1997-2001, and pp. 20-25, Forecasted Patterns in Residential Gas Consumption, 2001-2020.

¹⁴ *Id.*, p. 4, Chart 2.

¹⁵ *Id.*, p.15.

¹⁶ *Id.*, pp. 3, 20.

assertions of the neutrality of decoupling mechanism are hollow. As a practical matter, ratepayers can expect to continue to pay more as use declines over time as compared with some past baseline level.

22. To sum up, one of the most blatant flaws of decoupling is its overbreadth.. While PSE and other proponents repeat the mantra that decoupling will enable PSE to solve the dilemma “that, for every therm saved due to energy conservation, PSE fails to recover another unit of its authorized distribution margin.”¹⁷ Decoupling goes far beyond that. This is not just a conceptual problem. It has serious financial consequences for customers, as discussed later in the brief.

3. The focus on declining use per customer is misleading; total sales volumes are stable.

23. All three decoupling proposals in this case single out the declining trend of usage per customer. At the same time, PSE and other proponents ignore the total sales of the Company. It is undisputed that there is a trend of declining use on a per-customer basis, but despite that trend, PSE’s 2004 Annual Report shows that overall sales volumes have been relatively stable in recent years, despite warmer than normal weather in each of the last three years. In fact, volumes for 2005 are higher than the two preceding years.¹⁸ These facts seriously undermine Mr. Amen’s assertion that unpredictability of gas usage and the impact of weather on financial condition justify adoption of decoupling.¹⁹

24. The reality is that PSE gas margin revenues are growing as a result of adding customers and raising rates through rate proceedings. PSE’s Gas Commission Basis Reports show that gas margin revenues from sales to customers (less purchased energy costs) have grown from \$230

¹⁷ Exh. No. 21, p. 26:16-19.

¹⁸ Exh. No. 506, p.34 (Brosch).

¹⁹ Exh. No. 21, p. 26:7-21 (Amen).

million in 1997 to about \$336 million in 2005, an increase of more than \$100 million.²⁰ This shows that a major reason for stability of sales volumes is revenues provided by new customers.

PSE has strong customer growth. PSE's 2004 annual report boasts:

Puget Sound Energy hooked up approximately 27,000 new [natural gas] customers in 2004, exceeding the national average for growth in natural gas customers. This continued progress is a tribute to PSE's dedicated employees who work hard to deliver reliable, cost-effective, high-quality service."²¹

Company Senior Vice President Kimberly Harris testified at hearing that she hopes the trend of adding new customers will continue.²² Similarly, PSE witness Ms. McLain testified at hearing that most utilities view growth in customers and growth in revenues as positive.²³ The Company certainly does not treat the addition of new customers as an undesirable or financially detrimental factor.

25. PSE's GRNA proposal does not track the favorable effects of sales growth from new customers for the benefit of ratepayers. Instead, the GRNA retains these benefits for shareholders. This is accomplished by adding to its existing revenues (Base Line Margin) all of the revenues associated with new customer growth (Customer Growth Adjustment). PSE thus adds more margin to the amounts against which actual margin is tracked.²⁴ This has the effect of amplifying future revenue growth by increasing delivery prices for conservation effects on per customer sales, while letting PSE retain all revenue growth associated with adding new customers.²⁵ Back-casting the effects of the GRNA to 2001 shows that it would have generated

²⁰ Exh. No. 506, p.35:1-3 (Brosch).

²¹ 2004 Annual Report to Shareholders, p.15. This annual report was included as part of PSE's initial rate case filing in this docket.

²² Harris, Tr. 150:19-24.

²³ McLain, Tr. 204:12-19.

²⁴ Exh. No. 506(C), p.35:17-20 (Brosch).

²⁵ Exh. No. 506, p.36:7-12, footnote 19 (Brosch).

approximately \$30 million dollars over the five year period, and nearly \$10 million in 2004 and 2005 alone.²⁶

26. As Public Counsel witness Brosch testified on cross-examination:

[I]t's problematic to select usage per customer where there is an obvious declining trend and provide piecemeal ratemaking and interim rate increases between test years while ignoring and presuming unimportant the continuing revenue growth arising from serving new customers and the margins earned from serving new customers.²⁷

C. Decoupling Is An Expensive Blunt Instrument.

1. PSE actual losses through its gas conservation efforts are small.

27. As noted above, the proponents cite as justification for decoupling the revenues that PSE foregoes when it encourages its customers to conserve natural gas. Ms. Steward's testimony refers to the "margins lost due to customer efficiency."²⁸ During colloquy with Chairman Sidran, Mr. Weiss of NWECA stated "...to assume that a utility can constantly support a program that loses it money is – I think is not credible really."²⁹ Given these assertions, one would expect the amount of lost revenues to be large enough to be, in PSE witness Amens' words, a "significant financial disincentive."³⁰ Public Counsel witness Michael Brosch points out, however, that PSE sponsored programs appear to only produce a modest impact on gas sales volumes and margin revenues.³¹ PSE has set a gas energy efficiency stretch goal of 2.1 million therms for each of the years 2006 and 2007 (for a total goal of 4.2 million therms over two years). This represents only about 0.2 percent of PSE's annual sales of over 1 billion therms.³² *Id.*

²⁶ Exh. No. 506, p.37:1 (Table)

²⁷ Brosch, Tr. 661:10-17.

²⁸ Exh. No. 561, 6:4 (Steward).

²⁹ Weiss, Tr. 696:12-14.

³⁰ Exh. No. 21, p. 28: 2 (Amen).

³¹ Exh. No. 506C, p. 42:11 (Brosch).

³² If sales to transportation customers are removed from this calculation, as NWECA witness Mr. Weiss recommends in his cross-answering testimony (Exh. No. 504, p. 7), the proportion increases from .2 to .26 percent. The

28. In dollar terms, if PSE achieves the 2.1 million therms “stretch goal” mentioned above, the Company’s lost margins are estimated at \$1.035 million for the two year period 2006-2007, or only \$517,789 on an annual basis.³³ Even this estimate may be overstated, because it is based upon PSE achieving their “stretch target.”³⁴ At hearing, while PSE witness Mr. Shirley indicated “the 2.1 million therms we have currently as our target was significantly vetted through our own analytical process, and in negotiations with the CRAG,”³⁵ he also stated: “[w]hen we typically set a stretch target, the stretch target usually means that there’s probably as much as an 80% chance of us not meeting that target.”³⁶ To the extent PSE does not reach their stretch target, the actual amount of lost margins would be lower.³⁷

29. PSE’s estimated lost margin amount of approximately \$517,789 annually represents about .07 percent of PSE’s total gas operating revenues from residential, commercial, and industrial sales of \$743.6 million.³⁸ When compared to the Company’s actual gas operating revenues during the test year of \$879,440,289, PSE’s lost margins represent only about .059%.³⁹

2. Decoupling generates revenues that far exceed the size of the problem.

When PSE’s total estimated lost margins from the Company’s gas energy efficiency programs are compared to the total amount the Company would collect from ratepayers under the various decoupling proposals before the Commission, it is abundantly clear that these decoupling mechanisms would require ratepayers to provide PSE with additional revenues that

Company’s 2004 Annual Report to Shareholders shows retail sales volumes (non-transportation) of 808,558,000 therms in 2004. $2.1M / 808.6M = .26\%$. (p. 37).

³³ Exh. No. 571, p. 3.

³⁴ Steward, Tr. 727:7-9, also Commission Staff witness Ms. Steward also points out that the estimated lost margins may be higher, because her calculations used current rates. Tr. 727:1-6.

³⁵ Shirley, Tr. 592:24-593.2.

³⁶ Shirley, Tr. 593:9-12.

³⁷ Steward, Tr. 727:10-12.

³⁸ 2004 Annual Report, p. 49 (included in PSE initial rate case filing).

³⁹ Exh. No. 230, p. 2:5 shows actual gas operating revenues of \$879,440,289. $\$517,789 / \$879,440,289 = .059\%$.

far exceed the amount of lost margins. PSE's GRNA might collect from 36 to almost 50 times as much as the Company's annual lost margins of \$517,789, based upon the Company's simulation using proposed rates, as shown in the table below. Even if one considers only the cumulative estimated lost margins of \$1,035,578 for the two-year period 2006-2007, PSE might collect 18 times that amount in 2007 under the GRNA, according to PSE's simulation.

Table 2: Summary of PSE's GRNA Simulation Under PSE's Proposed Rates

	2007	2008	2009
Residential	\$15,795,430	\$21,236,125	\$17,323,918
C&I General (Sch 31)	\$2,487,378	\$3,512,280	\$2,174,307
C&I Heating (Sch. 36)	\$547,445	\$853,941	\$501,859
Total	\$18,830,253	\$25,602,346	\$20,000,084

Source: Exhibit 563. The original source of this data is also shown in Exhibit 59C (PSE response to Staff data request 173). Revenue from apartment building customers, included in Exhibit 59C, is not shown here.

30. Perhaps the most appropriate term to characterize the additional revenues PSE would realize as a result of the GRNA decoupling mechanism is "windfall," as Mr. Weiss of the Energy Coalition admitted at the hearing.⁴⁰

A. [Mr. Weiss]: The existing customers, our proposal and the Company's proposal would allow for somewhat of a windfall, they would recover for that group, and that's one of the reasons why we have tied our conservation targets to the recovery of those margins, because otherwise there would be somewhat of a windfall from the existing customer downward trend.

Q. [Mr. ffitich]: You use the word windfall, it is possible, is it not, that if you don't design a decoupling proposal correctly, you can create a windfall for a utility Company?

A. Yes.⁴¹

⁴⁰ Weiss, Tr. 683:13-14.

⁴¹ Weiss, Tr. 683:12-23.

31. But while NWEAC recommends conservation targets as part of their proposed decoupling mechanism, their proposal would still provide PSE with substantial additional revenues outside of a rate case, revenues that far exceed the Company's lost margins from energy efficiency programs. For example, under NWEAC's decoupling proposal, if PSE achieves its 2.1 million therms conservation target for 2007, the Company would recover 50% of their approved margin.⁴² PSE's simulation of the GRNA, shown in the table above, estimates \$18.8 million of additional revenues for 2007, so under the NWEAC proposal this would result in about \$9.4 million in increased rates.

32. Proponents of decoupling may argue that PSE's GRNA simulation is based on warmer than normal weather, which contributes to higher revenue shortfall. However, even if we consider Staff's proposed "partial decoupling," which would attempt to remove the change in usage due to variations from 'normal weather,' residential ratepayers would still be exposed to an additional \$8 million per year, as shown in the table below.

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⁴² Exh. No. 502, p. 11: 8.

Table. 3: Summary of Potential Residential Rate Increases Under Staff's 'Partial Decoupling' Mechanism

	2007	2008	2009
Residential	\$7,730,125	\$8,084,258	\$8,329,527

Source: Exh. No. 565 (JRS-5). This exhibit is a simulation with an assumption of a 5% decrease in new customer usage. Staff's recommendation is that actual usage of new customers be used in their partial decoupling mechanism. Tr. 723:4-24.

3. PSE lost margins due to Company sponsored conservation are even more minimal when seen in context.

33. In an attempt to depict the scope of the problem that PSE witness Mr. Amen refers to as the "significant financial disincentive," we have prepared the following table comparing PSE's estimated lost margins from the Company's natural gas energy efficiency programs to various expenses and potential rate increases from the different decoupling proposals in this case.⁴³

Table. 4: Comparison of PSE's Estimated Lost Margins from Natural Gas Energy Efficiency Programs to Various Expenses and Potential Rate Increases from Decoupling

Description	Amount	Source
Annual estimated lost margins from natural gas energy efficiency programs (2006 – 2007)	\$517,789	Exh. No. 571, p.3
Total amount billed as of Sept 14, 2006 for PSE's 4 outside expert witnesses	\$673,805	Rev. Exh. No. 448
Total estimated billings for PSE's 4 outside experts in this docket	\$787,500	Rev. Exh. No. 448
Restricted stock awards to Stephen Reynolds, CEO, in 2005 (vesting date of 2008, designed to be fully tax deductible).	\$882,381	Exh. No. 177, p. 10; Exh. No. 6
Total (cumulative) estimated lost margins, 2006-2007, if PSE achieves 'stretch' conservation target	\$1,035,578	Exh. No. 571, p.3
Total value of 2005 compensation to Stephen Reynolds, including grants of restricted stock and performance-based awards	\$3,014,274	Exh. No. 177, p. 10.
Total value 2005 compensation to top 5 PSE officers, including grants of restricted stock and performance-based awards	\$5,184,018	Exh. No. 177, p. 10.

⁴³ Exh. No. 21, p. 28:2.

Total estimated increase to <i>residential</i> ratepayers in 2007 under Staff’s proposed “partial decoupling” mechanism (PSE simulation, without weather, 5% decrease in new customer usage assumed).	\$7,730,125	Exh. No. 565 (Steward)
Total estimated increase to residential, commercial, and certain industrial ratepayers in 2007 under PSE’s proposed GRNA decoupling mechanism (PSE simulation under proposed rates; Sched. 23, 31, 36).	\$18,830,253	Exh. No. 563 (Steward) (summary of data in Exh. No. 59C)
Total estimated increase to <i>residential</i> ratepayers from Staff’s 3-year (2007-2009) “partial decoupling” pilot (PSE simulation, without weather, 5% decrease in new customer usage assumed).	\$24,143,910	Exh. No. 565 (Steward)
Total estimated increase to residential, commercial and certain industrial ratepayers first three years (2007-2009) under PSE’s proposed GRNA decoupling mechanism. (PSE simulation under proposed rates; Sched. 23, 31, 36).	\$64,432,683	Exh. No. 563 (Steward) (summary of data in Exh. No. 59C)
Total PSE gas operating revenues, 12 months ended September 30, 2005.	\$879,440,289	Exh. No. 230, p.2 (Karzmar)

D. Decoupling Is Not Necessary to Cause PSE to Pursue Energy Efficiency.

1. PSE has a long standing commitment to energy efficiency rather than a culture of hostility.

34. One of the arguments advanced by NWECA in favor of decoupling is that it is critical to changing a utility company’s corporate culture from opposition or reluctance to support for company-sponsored conservation. As NWECA witness Steve. Weiss puts it “[a] decoupling mechanism is essential to establishing a corporate culture that promotes aggressive cost-effective conservation investments.”⁴⁴ According to Mr. Weiss, absent decoupling, companies can be expected to oppose or disfavor direct utility investment in energy efficiency, to discourage customer sponsored conservation, and to oppose adoption of policies such as efficient appliance standards or building codes:⁴⁵

⁴⁴ Exh. No. 502, p. 5:18-20 (Weiss).

⁴⁵ Exh. No. 502, p.3:21-4:2 (Weiss).

35. The problem is that there is no connection between this hypothetical recalcitrant utility behavior and most of companies regulated by this Commission. Particularly in PSE's case, when actual conservation performance is examined, it simply doesn't fit with NWECA's premise. PSE has elevated responsibility for energy efficiency to the senior vice president level and both Kimberly Harris, Senior Vice President for Regulatory Affairs and Energy Efficiency and Cal Shirley, Vice President of Energy Efficiency Services testified in this case. Ms. Harris agreed that PSE has a strong and long-standing commitment to energy efficiency initiatives. As she put it, "[PSE's] conservation programs span decades, we have been a leader in conservation for decades."⁴⁶ She acknowledged that PSE improved its conservation programs in the 2001 rate case settlement,⁴⁷ and observed that that they have a "very active and enhanced program."⁴⁸ The record contains a detailed description of PSE's energy efficiency programs.⁴⁹ PSE supports both direct and indirect utility investment in programs to reduce energy use.⁵⁰ Ms. Harris was unaware of any action by PSE during her tenure from 1999 to the present to discourage its customers from paying for measures to reduce their own energy use.⁵¹ Ms. Harris could not cite any instance since she became Senior Vice President in 2004 when PSE has opposed adoption of energy efficient building codes or appliance standards.⁵²

36. Mr. Shirley confirmed Ms. Harris' testimony when he took the stand at hearing, agreeing that PSE has a strong long-term commitment to energy efficiency in both electric and gas

⁴⁶ Harris, Tr. 115:13-22.

⁴⁷ Harris, Tr. 116:2-11.

⁴⁸ Harris, Tr. 116:15-16.

⁴⁹ Exh. No. 399, p. 4.

⁵⁰ Harris, Tr. 117:2-8.

⁵¹ Harris, Tr. 117:9-13.

⁵² Harris, Tr. 118:18-21.

service.⁵³ He testified he was not aware of any active PSE opposition to energy efficient appliance standards, building codes, or to customer sponsored conservation during his tenure,⁵⁴ stating that on the contrary, PSE has typically “advocated” in support of such efforts. NWECA witness Weiss admitted he did not believe PSE had engaged in anti-conservation activities.⁵⁵

37. While Mr. Weiss, as noted, has made the “corporate culture” argument, he readily admits that PSE is performing well. In response to questions from Chairman Sidran, he acknowledged this, stating: “But I must admit that the Company is very good, and the day before decoupling and the day after decoupling they might not change that much.”⁵⁶ How well PSE is doing generally is further borne out by PSE’s response to Bench Request No. 9. The response indicates that PSE has achieved much more conservation, in total and on a per-customer basis, compared to Northwest Natural Gas’ performance in Oregon subsequent to that Company’s implementation of a decoupling mechanism.

2. PSE has existing legal and public service obligations to pursue energy efficiency.

38. An important fact that has not generally been highlighted by the proponents of decoupling in this proceeding is that PSE already has an existing legal obligation to pursue cost-effective energy efficiency. The Commission’s rule regarding integrated resource plans (IRP) requires gas utilities to file a plan every two years “describing the mix of natural gas supply and conservation designated to meet current and future needs at the lowest reasonable cost to the utility and its ratepayers.” WAC 480-90-238 (2)(a). Moreover, as part of the Conservation

⁵³ Shirley, Tr. 585:6-10.

⁵⁴ Shirley, Tr. 585:11-586:6.

⁵⁵ Weiss, Tr. 682:2-8

⁵⁶ Tr. 696:14-17.

Settlement in Puget Sound Energy's 2001 general rate case, the Company made the following commitment:⁵⁷

The programs funded through PSE's tariff rider and natural gas tracker will be designed to achieve all savings that are not independently captured by consumer acquisition, that are cost-effective to the Company, and economically feasible for consumers, taking into account incentives provided by PSE.⁵⁸

This commitment requires PSE to commit to pursue all cost-effective energy efficiency, as PSE witness Mr. Shirley confirmed at hearing.⁵⁹

39. In addition to these legal obligations, the Company has made it clear that they also offer conservation programs because customers expect them to do so as part of their public service obligation. For example, PSE's August 29, 2006 press release regarding its Purchased Gas Adjustment (PGA) rate increase encouraged customers to participate in energy efficiency programs. The press release states in part:

"While our geographic location and purchasing strategies help keep our customers' natural gas costs lower than elsewhere in the nation, we urge customers to follow some simple steps to help control heating bills this winter," said Darren Brady, PSE's senior vice president of Customer Services. "These include taking advantage of our energy-efficiency services and rebates to help customers save energy *and* money."⁶⁰

At hearing, Ms. Kimberly Harris, PSE's Senior Vice President for Energy Efficiency, agreed that the press release actively highlights and promotes the Company's energy efficiency programs.⁶¹ Offering these programs, and making customers aware of them, is something the Company

⁵⁷ *WUTC v. Puget Sound Energy*, Docket Nos. UE-011570 and UG-011571, Twelfth Supplemental Order (Approving and Adopting Settlement Stipulation), June 20, 2002, Exhibit F to Settlement Stipulation, (hereafter, "2002 Conservation Settlement").

⁵⁸ Exh. No. 373, p.1 (section C.3).

⁵⁹ Tr. 577:24-578:20.

⁶⁰ Exh. No. 178, p. 1. The press release also suggests PSE customers call a PSE Personal Energy Advisor, at 1-800-562-1482, and request the free brochure "How to Reduce Your Gas and Electric Costs, and directs customers to the utility's Web site (www.pse.com) for "a variety of useful energy-saving ideas." Exh. No. 178, p. 2.

⁶¹ Tr. 120:18 – 121:4.

should do as part of its public service obligation. Ms. Harris added at hearing, in discussing this press release, “We believe that it is a service to our customers to make sure they understand the opportunities and services we have available for them.”⁶²

40. As Public Counsel witness Mr. Brosch testified at hearing, providing energy efficiency programs is in the Company’s own interest:

I think that utilities have an interest in promoting the efficient use of their service. I think it’s necessary to do that to be competitive, I think it’s necessary to do that to satisfy the interests of the public and regulators in overseeing and regulating the Company’s business.⁶³

This attitude is further reflected in PSE’s own 2004 Annual Report to Shareholders, which includes a profile of Rick Yoder, PSE customer and owner of Wild Ginger Restaurant in Seattle. The profile includes the following quote from Mr. Yoder: “Unsolicited, Puget provided us with a free energy audit. That’s a long term view that may result in selling us less gas today, but keeping us as customers tomorrow.”⁶⁴

3. PSE is already stretching the limits of available natural gas energy efficiency.

41. As discussed earlier, the proponents of decoupling argue that decoupling will have a positive impact on PSE’s natural gas energy efficiency efforts. A consistent theme, however, heard from Company witnesses in this case is that PSE is essentially already stretching the limits of achievable energy efficiency in the natural gas market. This raises an important question: what purpose is served by putting ratepayers at risk for an additional \$8 - \$25 million per year from decoupling when there is no real expectation that more efficiencies can be gained based on PSE’s own characterization of the natural gas energy efficiency market.

⁶² Tr. 122:1-3.

⁶³ Tr. 666:16-21.

⁶⁴ 2004 Annual Report to Shareholders, p.7.
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42. PSE's Vice President for Energy Efficiency, Mr. Shirley, testified at hearing that in his view, the natural gas energy efficiency market is not as mature or well developed as the electric energy efficiency market. He believes this is a nationwide phenomenon, not confined to Washington State.⁶⁵ During colloquy with Commissioner Jones, Mr. Shirley explained, "On the electric side we have been doing, like a lot of utilities, electric energy efficiency for nearly 30 years. We have about half that time doing gas."⁶⁶ As a result of that more limited experience on the natural gas side, Mr. Shirley explained, the trade ally network "is not nearly as practiced in terms of energy efficiency on the gas side as it is on the electric."⁶⁷ These fundamental structural differences between the electric and natural gas energy efficiency markets were also revealed in the energy service market's response to PSE's November, 2005 Request for Proposals (RFP) for demand-side or energy efficiency resources. In his rebuttal testimony, Mr. Shirley states the following:

In response to this RFP, the Company received five bids for natural gas efficiency. After an extensive evaluation process, none of these proposals showed enough potential to be selected. From the energy service market's response to the RFP, *it is apparent that there are no easy or obvious solutions to acquiring significantly more gas energy savings.*⁶⁸

In contrast to the small number of gas proposals, PSE received thirteen electric proposals and selected three energy efficiency proposals, and two demand response proposals.⁶⁹

43. PSE has also identified a range of barriers or challenges that help explain why the Company's gas conservation target for 2006-2007 is below the Least Cost Plan (LCP)

⁶⁵ Shirley, Tr. 625:4-20.

⁶⁶ Shirley, Tr. 622:3-6.

⁶⁷ Shirley, Tr. 621:25-622:3.

⁶⁸ Exh. No. 379, 26:7-11. (Shirley; emphasis added). PSE updated this to six proposals in Exh. No. 395.

⁶⁹ Exh. No. 395, p. 2.

guidance,⁷⁰ including a lack of qualified contractors.⁷¹ PSE has emphasized that these kinds of “practical challenges and uncertainties” associated with program implementation were considered when establishing the gas savings target, but were not reflected in the LCP, which helps explain why the gas conservation targets are lower than the LCP guidance.⁷² On the electric side, however, PSE’s 2006-2007 conservation target exceeds the guidance from the LCP.⁷³

E. Decoupling Violates Basic Principles of Balanced Ratemaking.

44. Decoupling, in any of the forms proposed in this case, is a piecemeal rate tracking device designed to change rate levels between cases for post-test year changes in gas usage per customer.⁷⁴ Public Counsel witness Michael Brosch discusses in his direct testimony why a discussion of traditional test year regulation, versus rate tracking and deferral accounting is relevant to this case.⁷⁵
45. A fundamental problem with decoupling as a tracking mechanism is that it can seriously distort the “matching principle” that is desirable in a rate case test year. The “matching principle” recognizes the importance of matching all revenues and costs (expenses, rate base, rate of return) at a consistent period of time to determine needed changes in utility pricing.⁷⁶ All elements of the revenue requirement calculation are dynamic. Cost increases in one area can be offset by cost decreases, or revenue increases in other areas, or vice versa. For example, adding

⁷⁰ Exh. No. 394, p. 2.

⁷¹ Exh. No. 396, p.2

⁷² *Id.*, See also, Exh. No. 379, pp. 26-27 (Shirley Rebuttal).

⁷³ Exh. No. 394, p. 2.

⁷⁴ Exh. No. 506, p.11:1-16 (Brosch).

⁷⁵ *Id.*.

⁷⁶ *Id.*, p. 11:17 – p. 12:7.

customers and the related revenue growth can help offset any increase in operating expense.⁷⁷

The Commission has recently reaffirmed the application of this principle for ratemaking in Washington, *WUTC v. Avista Corporation*, Docket Nos. UE-050482, UG-050483, Order No. 05, ¶ 111.

46. Commission Staff witness Steward’s testimony confirms that the adoption of a decoupling mechanism can disturb the matching principle. She expresses a concern with allowing a decoupling mechanism to go on too long because “we risk violating the cost-based principle of regulation, creating a potential mismatch between current costs and rates.”⁷⁸ It is ratepayers that will bear the risk of the unfair rates that would result.
47. An additional significant problem raised by this issue is that it is potentially very difficult to correct. Unless PSE files a general rate case during or at the end of the pilot, the burden of proof would be on customers or the Commission to show that the violations of the matching principle were occurring. Rates could be distorted. Overearnings, even windfall profits, could occur for the entire period of the pilot, and continue in any renewal period. This could not be reviewed and corrected unless a complaint against general rates were brought by a party other than PSE.

F. Decoupling In This Case Violates the Guidelines of the Commission’s PacifiCorp Order.

48. In the most recent PacifiCorp general rate case order, the Commission set out a 12-point list of components to be addressed in a decoupling mechanism.⁷⁹ PSE’s proposal in this case either omits or fails to adequately address a number of these.

⁷⁷ Exh. No. 506, p. 12:8-17. Brosch , Tr. 674:7-11.

⁷⁸ Exh. No. 561, p. 20-22..

⁷⁹ *WUTC v PacifiCorp*, Docket No. UE-050684, Order No. 04, ¶¶ 108-109 (PacifiCorp Order).

1. Cost of capital.

49. The PacifiCorp order requires that a decoupling proposal address the “rate of return” implications of the proposal.⁸⁰ Because decoupling shifts significant risks from shareholders to ratepayers, adoption of any decoupling proposal should be reflected in a downward adjustment to the cost of capital. PSE’s recommendation in this case is to instead, increase its authorized return on equity, notwithstanding its request for approval, not only of decoupling but of two other risk shifting proposals (the depreciation tracker and the PCA modifications). This issue is discussed more generally in the Cost of Capital portion of the brief.

2. Incremental conservation measures.

50. In the PacifiCorp order the Commission rejected the joint electric decoupling proposal offered by PacifiCorp and the Natural Resources Defense Council (NRDC), in part because “The Company has failed to identify and commit to incremental conservation measures as a counterbalance to its potential reduction in risk.”⁸¹ In this case, PSE fails the same test. The Company has made no specific commitment to any additional measures or incremental energy efficiency programs that would be undertaken as part of their proposed decoupling mechanism. Indeed, PSE’s decoupling witness, Mr. Amen, stated at hearing that he did not even focus on PSE’s conservation efforts or the degree to which they would increase,⁸² though he went on to say that “it’s been my experience that the Company would do everything it possibly could; that is what is cost-effective[.]”⁸³ Mr. Amen failed to identify any specific incremental conservation

⁸⁰ *Id.*

⁸¹ PacifiCorp Order at ¶108.

⁸² Amen, Tr. 529:9-18.

⁸³ Tr. 530:13-16.

efforts in response to Commissioner Oshie's question.⁸⁴ PSE also opposes the inclusion of any conservation targets in the decoupling mechanism.⁸⁵

51. Despite the Commission's guidance in the PacifiCorp Order, Commission Staff has said that they do not expect a decoupling mechanism to result in incremental conservation benefits for PSE's customers. At hearing, Staff witness Ms. Steward indicated that "for this utility, I'm not looking for incremental conservation, because I think customers have already been getting that benefit."⁸⁶

52. Chairman Sidran asked Staff witness Ms. Steward at hearing about Staff's lack of any specific expectation that any incremental conservation measures would be undertaken as a result of decoupling:

Q. [Chairman Sidran]: All right, maybe just one follow up. If you can't identify any particular incremental conservation goal, why is the decoupling mechanism going to advance the conservation objective? I mean I understand the Company's problem that you have identified on the recovering its margin, but I don't quite understand the decoupling mechanism as a conservation tool in the context that you described.

A. [Ms. Steward]: Yeah, that was a dilemma actually when we started working on this for this utility, because I think they already have stepped up and made that commitment. I think customers have already benefited from that. But I didn't feel comfortable saying, well, since they've already done that, then we shouldn't do a decoupling mechanism, because they have been the ones incurring the lost margins from their programs, so it – I can't say that there will be incremental benefits, but it certainly, I think the same as with the incentives on the electric side, *it will hopefully not hold them back* since they have nothing to lose from the lost margins by within each program period of capturing all the cost effective conservation they can on the gas side.⁸⁷

⁸⁴ Tr. 528:4-531:12.

⁸⁵ Exh. No. 31, p. 3:19-20 (Amen).

⁸⁶ Tr. 747:25-748:2.

⁸⁷ Tr. 767:9-768:5 (emphasis added).

53. Staff's stated premise is that "[o]ne of the primary goals for a decoupling mechanism is to remove a utility's disincentive to promote energy efficiency."⁸⁸ If Staff also says they do not expect incremental conservation efforts from PSE as a result of decoupling, it is unfair to ask ratepayers to pay as much as an additional \$8 million to \$25 million per year under a decoupling mechanism. Again, decoupling appears to offer ratepayers the very real potential for significant rate increases outside of a rate case, and little, if anything in the way of incremental conservation benefits.

3. Low-income customer impact.

54. Another issue which the PacifiCorp order requires decoupling proponents to address is the impact on low income customers.⁸⁹ Commission Oshie pressed Mr. Amen on the point that as customers in a class conserve, the shortfall in fixed costs will be spread across everyone in the class. For those that cannot afford to make their homes or appliances more efficient, over time those customers will pay more and more of the overall cost to the class. Mr. Amen agreed with this assumption.⁹⁰ He also stated it is the responsibility of the provider of energy conservation programs to ensure low income customers have the ability to fund those conservation measures.⁹¹

Commissioner Oshie questioned Mr. Weiss on the same point and Mr. Weiss also agreed with the Commissioner's assumption:

A. [Mr. Weiss]: I would agree with Mr. Amen's conclusion, it does do what you say, there's no doubt about it, but there's a few things that mitigate. One is that one thing you do is you ramp up your low income programs, both assistance and weatherization, so even the customers who can't do much conservation. But everybody can put in an efficient light bulb I mean. But you've got to ramp up programs, so that is true. The

⁸⁸ Exh. No. 561, 5:20-21.

⁸⁹ PacifiCorp Order, ¶ 109.

⁹⁰ Amen, Tr. 533:24-534:23.

⁹¹ Amen, Tr. 534:15-20.

second fact is that if the savings from this are reflected in a lower rate of return, it lowers everybody's bills. I think the numbers are going to show that the lowering in bills is almost comparable to, except for a very warm year where you have a big, big surcharge, the lowering of the bill through rate of return reduction pretty much balances out that effect. So you offer a lot of – you offer everybody a program, you fund it very well, but there is some risk, yes, I agree.”⁹²

Notably, Mr. Weiss' premise here is that impact on low-income customers can only be mitigated if gas energy efficiency programs (presumably something other than light bulbs) are ramped up and if rate of return reductions are so sizeable as to offset rate increases. These points might be made for all ratepayers. Neither of these conditions is present in this case.

G. Decoupling Introduces Unnecessary Technical Complexity and Burdens to Regulation.

1. There are wide disparities among proponents about how best to implement decoupling.

55. One indication of the problems with decoupling is the veritable cacophony of voices, even among supporters, about how it should work. While all proponents contend there is at least some relationship between decoupling and conservation, they don't agree on how much. The proponents disagree about many components, including: whether weather should be included in the mechanism; what is the correct weather normalization methodology (see below); how to account for new customers (see below); whether there should be conservation targets; whether receipt of decoupling revenue should be linked to performance against those targets; and, about whether decoupling alone is enough to motivate pursuit of energy efficiency.

56. Cal Shirley, in his rebuttal testimony in this case, recalled this Commission's guidance with respect to the establishment of new regulatory mechanisms in Docket No. UE-900385.⁹³ There the Commission identified four general principles such programs: it must be measurable; it

⁹² Tr. 714:12-715:3.

⁹³ Exh. No. 379, p. 6:15-19, (Shirley).

must be simple to administer; it must be intuitive enough to allow a straightforward explanation to customers; and, it must be an improvement, on balance, over the current method of regulation. The decoupling proposals in this case fall short of these principles.

2. Weather normalization.

57. All three decoupling mechanisms would require a weather normalization methodology, as part of the calculations that would be performed to annually set customer rates. This represents another example of the technical complexities involved in the proposed decoupling mechanisms. Staff's 'partial decoupling,' which excludes weather from the mechanism, requires calculations to estimate the changes in usage resulting from variations from 'normal weather,' however that is ultimately defined as part of this proceeding.⁹⁴ As Public Counsel witness Mr. Brosch stated in his direct testimony, "Puget's GRNA proposal would adjust rates to eliminate gas usage and revenue fluctuations due to weather or conservation effects, effectively guaranteeing collection by the utility of the gas margin revenue per customer that was used to set rates. At the same time, PSE would be allowed to collect and retain for its shareholders (not track through rates) steadily increasing margin revenues associated with adding new customers."⁹⁵

58. PSE's gas margin revenue per customer used to set rates is established using weather-normalized gas volumes, as determined in the rate case.⁹⁶ Based upon the fact that PSE estimates it will spend a total of \$380,000 on its weather normalization witness, Dr. Dubin, it would appear that the Company is extremely concerned with the particular assumptions and mechanics

⁹⁴ Tr. 728:14-19. Exh. No. 570.

⁹⁵ Exh. No. 506C, p. 32:12-17.

⁹⁶ See, e.g. Exh. No. 552, pp. 3-5 (Mariam).
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embedded in the weather normalization methodology that may ultimately be adopted in this case.⁹⁷ Weather normalization was a contentious issue in this case, and was the focus of an ongoing collaborative between the Company and Commission Staff.⁹⁸ Commission Staff witness Dr. Mariam stated in his direct testimony that PSE failed to perform a load research study to justify its proposed change in base or balance point temperature.⁹⁹ Dr. Mariam recommends Commission acceptance of PSE's weather normalization methodology, but for purposes of this case only.¹⁰⁰ Dr. Mariam has recommended the Commission order PSE to take several steps to overcome the deficiencies with the Company's methodology.¹⁰¹ Customer rates would be adjusted each year that a decoupling mechanism is in place, presumably using the weather normalization methodology accepted by the Commission for this case, a mechanism still in dispute.¹⁰²

3. New customers.

59. PSE, Staff, and NWEAC contend that in order to make an "apples-to-apples" comparison, revenues from new customers must be taken into account. As discussed in Section B.3 above, all three of their proposed mechanisms would add the revenue from new customers to the "baseline" margin the Company would be allowed to recover each year. At that point the proposals diverge. PSE and Staff recommend competing methodologies for calculating new customer impact. NWEAC proposes either postponing resolution of this issue to a collaborative where issues such as the impact of line extension policy would be considered, or simply leaving out new customers

⁹⁷ (Rev. Ex. No. 448).

⁹⁸ Tr. 449:1-13.

⁹⁹ Exh. No. 552, pp. 7:7-24.

¹⁰⁰ *Id.*, p. 6:10-12.

¹⁰¹ *Id.*, p. 8:22-9:5.

¹⁰² Exh. No. 570.

altogether because the issue is “so contentious.”¹⁰³ Regardless of the outcome of the debate, the end result is the same. The shareholders still receive the benefit of new customer revenue, however calculated, under any of the proposals.

4. Regulatory burden.

60. An additional drawback to adoption of a decoupling mechanism is the additional burden created on the Commission, its Staff, and consumer intervenors. New tariff filings are required, along with new audit procedures, and with discovery and dispute resolution procedures if disputes arise. Additional customer notice is required. Public Counsel disagrees with the sanguine predictions of other parties to this case about limited burden. Decoupling would add to the PGA, the PCA, and the PCORC, yet another fast-track filing and review process that allows constrained opportunities for either Staff, Public Counsel, or other intervenors to analyze, pursue discovery, or raise questions about the request before it goes into effect and changes rates. The ability of the ratepayers and their representatives to protect customers from unjustified charges in this kind of environment is compromised, when compared with the level of review in a rate case.

H. Decoupling Is Not a National Trend.

61. PSE also attempts to create the sense that decoupling is part of a national wave that this Commission should catch. Ms. Harris stated in her pre-filed testimony that decoupling is “widely accepted,”¹⁰⁴ though she was unable to say on cross-examination how many states have accepted and adopted this approach, deferring to PSE witness Amen.¹⁰⁵ Mr. Amen confirmed

¹⁰³ Weiss, Tr. 687:21-689:19.

¹⁰⁴ Exh. No. 173, p.12:4-5 (Harris).

¹⁰⁵ Tr. 122:8-124:5 (Harris).

that assertions of wide acceptance are simply not accurate. As of the time of the hearing, according to Mr. Amen, only five states in the country have adopted decoupling mechanisms for companies they regulate.¹⁰⁶

62. Decoupling is not a new idea. As Ms. Harris noted, the Commission approved a form of decoupling for PSE 16 years ago known as the PRAM (Periodic Rate Adjustment Mechanism). The PRAM was discontinued by agreement a few years later in 1995. In approving the termination the Commission noted a number of failings with the PRAM and observed that the PRAM had become “complex to administer, controversial, and difficult to explain to customers.”¹⁰⁷

63. Decoupling may be an idea whose time has passed, dating to an era when environmental issues, energy efficiency and renewables were finding difficulty gaining mainstream acceptance by utilities, policy makers and even consumers. Things have changed dramatically in the last quarter century, particularly in the Pacific Northwest. Virtually all of the major utilities in the region have active energy efficiency programs, public commitments to conservation goals, and real achievements in the field. Least cost planning (aka integrated resource planning) is taken seriously and is given substantial resources by the companies. There is broad consensus in support of energy efficiency. As discussed above, PSE has been a part of this trend. The fact that these developments have occurred without the benefit of decoupling mechanisms casts serious doubt on whether the underlying premise remains valid in today’s environment.

¹⁰⁶ Amen, Tr. 485:24. Exh. No. 50 (PSE response re decoupling activity, listing four at time of response). Subsequent to the hearing, one of the pending cases mentioned by Mr. Amen, *Citizens Gas in Indiana*, Exhibit No.50, p.4, has been decided, with the commission denying the decoupling (“VVCA”) request. *Petition of Citizens Gas & Coke*, Indiana Utility Regulatory Commission, Cause No. 42767, Order, October 19, 2006, pp. 77-84.

¹⁰⁷ Harris, Tr. 124:6-125:7. Exh. No. 176, p.2. PSE’s Periodic Rate Adjustment Mechanism (PRAM) was adopted in the Third Supplemental Order, *WUTC v. PSE*, Docket No. UE-901183-T, 901184-P. It was terminated in *WUTC*

I. RECOMMENDATION: If TheWUTC Wants To Encourage Additional Natural Gas Conservation, An Incentive Mechanism Is A More Appropriate Tool.

64. As this brief argues, decoupling, as proposed by PSE, NWEA, and Staff, is an expensive, complex, and ineffective way to address energy efficiency. If PSE is seeking decoupling simply for revenue stabilization and fixed cost recovery purposes, they have not made that case either. If the Commission concludes that PSE needs additional financial motivation to pursue conservation in its gas operations, Public Counsel believes that the Commission has a superior alternative available to it – an incentive/penalty mechanism for the gas side that parallels the proposals on the electric side in this case.

65. This case raises an obvious question. If parties are supporting an incentive payment mechanism for energy efficiency on the electric side, why isn't such a mechanism proposed on the gas side? None of the decoupling proponents seem to have a clear answer.

Cal Shirley's answer to Chairman Sidran's direct question on this point is revealing:

Q. [By Chr. Sidran]: Mr. Shirley, on the electric side the Company proposed a mechanism with measurable goals, incentives, and penalties. On the gas side, the Company proposed none of the above as part of its decoupling proposal. Why the difference?

A. [Cal Shirley]. The Company has made a decision that we would pursue decoupling to start out with on the gas side, and not an incentive. And I don't have anything more scientific to offer than that at this point.¹⁰⁸

This is a carefully worded non-answer. In essence, Mr. Shirley is saying "we decided to do it because we decided to do it, but I am not going to say why." For reasons unknown, PSE is not willing or able to disclose the specific Company reasons for this important policy choice.

66. When Chairman Sidran pursued the question of "why goals and incentives are a

v. Puget Sound Power & Light Co., UE-950618, Third Supplemental Order. The background and history of the PRAM is discussed at pp. 2-9.

¹⁰⁸ Tr. 623:9-19.

reasonable proposal on the electric side and not on the gas side,” Mr. Shirley made the curious argument that “it’s going to be a lot easier to start with one first, and see how we can make this work”¹⁰⁹ He went on to say “So I think it makes sense to start with one side of this, and especially where we have a lot more experience.”¹¹⁰

67. This rationale simply makes no sense. Important components of an incentive mechanism are already in place on both the electric and gas side. Energy efficiency targets have been established on both the gas and electric sides since the settlement of the 2001 rate case. The target setting process using the CRAG has been an effective and collaborative success story. The 2001 settlement also put in place penalties for not meeting targets on both the gas and electric side, as Mr. Shirley acknowledged.¹¹¹ Energy efficiency goal setting is also an important part of the IRP process. There are years of experience with those components and a long track record of support and cooperation among stakeholders. Building on this proven framework to adopt the electric incentive mechanism is an evolution, not a radical experiment. The same would be true on the gas side.

68. Mr. Shirley is telling the Commission that rather than build on this successful experience, PSE instead decided to propose an expensive, complicated, and untried mechanism, adopted in only five states in the country, that is a radical departure from fundamental ratemaking principles, and about which none of the proponents agree as to the correct way to implement. This hardly can be portrayed as the conservative option.

69. Public Counsel recommends that the Commission reject the choice made by PSE and

¹⁰⁹ Tr. 624:4-9.

¹¹⁰ Tr. 624:14-16.

¹¹¹ Tr. 623:19-23.

direct the parties to further develop a gas energy efficiency regulatory incentive building on past successes and the existing framework. A workable gas incentive mechanism would have the following components:

- An energy efficiency target would be set based on levels of therms saved through Company-sponsored energy conservation. The target would developed in consultation with the CRAG and approved by the Commission..
- Incentive payments tied to achievement of energy efficiency above the target levels, with increasing payment increments as levels of performance increase.
- Penalty payments would be incurred if energy efficiency performance fell significantly below target.¹¹²
- Payment levels would be scaled to revenues lost due to Company-sponsored conservation, as opposed to capturing all declines.
- A reasonable deadband that would avoid imposition of penalties or incentives if Company performance was within a certain proximity to the target. For example, the deadband could be such that if a “therms saved” was within 80 to 100 percent of the established target no penalty or incentive would accrue.
- Design criteria would be established to set threshold eligibility requirements to be met before incentives would be paid, similar to those recommended for the electric mechanism in Exh. No. 513.

Public Counsel respectfully requests that the Commission direct the Company to bring this issue to its existing CRAG and to file a proposal with the Commission for a gas incentive program either in its next general rate case filing, or by July 1, 2007, whichever is earlier.

IV. ENERGY EFFICIENCY INCENTIVE MECHANISM

A. Overview.

70. Public Counsel supports an electric efficiency incentive mechanism for PSE at this time to encourage the Company to expand upon the electric conservation efforts that were developed and implemented since the 2002 Conservation Settlement. We have made this determination

¹¹² Exh. No. 510, p. 13:3-12 (Klump). The penalties in the electric conservation incentive are tied to the amount the company could invest with third parties to achieve savings.

after careful review, and for a range of important reasons, as outlined in the testimony of Public Counsel witness Ms. Elizabeth Klumpp.¹¹³ Prior to requesting an incentive mechanism, the Company has demonstrated it has the professional capability and corporate commitment to aggressively pursue conservation. PSE's conservation targets increased after the 2002 Conservation Settlement from approximately 7-8 aMW of annual achievement in 2000-2001 to at least 15 aMW in the settlement to the current annual performance of 20 aMW in 2004 and 2005.¹¹⁴ PSE met its conservation targets, on average, in 2003, 2004 and 2005.¹¹⁵

71. In addition to its enhanced electric energy efficiency programs, PSE has taken other important steps that cause us to support an incentive mechanism at this time. These include the creation and development of the Conservation Resource Advisory Group (CRAG), and the experience that the Company and the CRAG have gained with the resource analysis and target-setting methodologies, by virtue of the fact that PSE has operated under a penalty mechanism since the 2002 Conservation Settlement.

72. In comparing the proposed incentive mechanisms now before the Commission, the proposals of the various parties—Public Counsel, Commission Staff, NWEA, and PSE—have considerable similarities. Public Counsel, Commission Staff, and NWEA jointly recommend twelve “Design Criteria for Electric Efficiency Incentive Mechanism.”¹¹⁶ These parties also utilize a similar two-part design to determine the level of any incentive payment. In the rebuttal testimony of Mr. Shirley, PSE modified its original proposal, recommending a structure similar to the other parties’ mechanisms, as well as some, but not all, of the “design criteria.”¹¹⁷

¹¹³ Exh. No. 510, 6:6-8:6. (Klumpp).

¹¹⁴ *Id.* 7:8-11.

¹¹⁵ Exh. No. 510, 3:7-8.

¹¹⁶ Exh. No. 513.

¹¹⁷ Exh. No. 379, 3:4-23:17.

B. Public Counsel Proposal.

73. Public Counsel's recommended incentive mechanism is set forth in the testimony and exhibits of Ms. Klumpp.¹¹⁸ We propose that financial incentives should be calculated based on total electricity savings. Our proposal includes two components in the incentive calculation. The first component is a dollar per megawatt-hour (MWh) saved figure. The second component is a "shared net incentive," designed in part to provide some motivation for the Company to manage its program costs. Taken together, the total incentive payments escalate as more conservation is achieved.¹¹⁹ The full detail of Public Counsel's proposal is outlined in Exh. No. 512.

74. With respect to the issue of what savings target should be used to evaluate PSE's performance as part of the incentive mechanism, Public Counsel recommends that the appropriate target is 20 aMW for 2007, or what the Company sometimes refers to as their "stretch" target. This target is one-half of the two-year savings goal that the Company filed with the Commission in its 2006-2007 Program Targets and Budgets.¹²⁰

75. Recognizing that the 20 aMW target represents an aggressive goal, upon which the Company's program budget and program mix is based, and also that the Company currently faces potential penalties if their performance falls below 16.5 aMW (under the terms of the 2002 Conservation Settlement), we propose to provide the first level of incentives at 90% of the 20 aMW "stretch" target, or for 2007, at 18 aMW. In this regard, our proposal has a "dead-band" from 80% to 90% of the Company's "stretch" target, which is currently 20 aMW.¹²¹

¹¹⁸ Exh. Nos. 510-514.

¹¹⁹ Exh. No. 510, 11:1-12:2.

¹²⁰ See Exh. No. 514 (ECK-5).

¹²¹ Exh. No. 510, 9:8-12. (Klumpp).

C. Response to Proposals of Other Parties.

76. As we have noted, there are many similarities between the various incentive mechanism proposals now before the Commission. A graphic representation of the different proposals is provided in Exh. No. 574. This exhibit shows, for example, that in general PSE and NWECA would provide for much higher levels of incentive payments to PSE at high levels of conservation achievement. In this section we highlight some of the major differences between the proposals.

1. PSE's Recommended Design Criteria Are Insufficient.

77. As noted above, Public Counsel, the Commission Staff and NWECA jointly recommend a set of "Design Criteria" for PSE's incentive mechanism – a list of requirements that are threshold issues for the Company to meet prior to being awarded incentives.¹²² These requirements are critical to ensure that ratepayers benefit from a diverse range of high-quality conservation programs, before PSE is deemed eligible for an incentive payment. The Company's proposed incentive mechanism incorporates many of these criteria, but falls short on several key elements.

a. The weighted average measure life of the total program portfolio must meet a minimum of 9 years to be eligible for an incentive.

78. All parties proposing an incentive mechanism reward the Company's shareholders based on the magnitude of savings the Company acquires in a year. This type of performance incentive should encourage the Company to achieve savings, but without threshold design requirements, it is very likely to encourage the Company to achieve the lowest cost measures that may also have

¹²² Exh. No. 513.

the shortest life, thus losing the opportunity to capture longer-term energy efficiency resources such as new residential or commercial construction, new heating or air conditioning equipment, and new refrigerators.¹²³ For this reason, we strongly oppose PSE's recommendation that there should be *no requirement* for a minimum average measure life. It is in the interest of the ratepayers and the power system to secure efficiency investments in long-term measures.

b. Three years is the appropriate sunset period for this incentive-penalty mechanism.

79. Instituting an incentive-penalty mechanism for electric energy efficiency for PSE would represent a significant policy change. The burden should be on the Company to demonstrate to the Commission and its stakeholders the results of the mechanism and its achievements in conservation at the end of three years, in order to justify continuation. As set forth in item eleven of the joint design criteria, the Company may file a request to extend or modify the mechanism beyond the three year pilot period, either as part of a general rate case proceeding or as part of a separate filing.¹²⁴ We believe three years is an appropriate duration for an initial pilot mechanism, and therefore oppose PSE's recommended duration of five years.¹²⁵ We also observe that in the event Initiative 937 becomes law, PSE would be required to meet certain conservation resource analysis requirements beginning in 2010, or not until after the three year pilot.

2. The incentive mechanism should utilize an aggressive target.

80. A key element of an incentive mechanism is the target level for conservation

¹²³ Exh. No. 510, 15:3-10. (Klump).

¹²⁴ Exh. No. 513, p. 3.

¹²⁵ Exh. No. 379, 23:10-17 (Shirley Rebuttal).

achievement that will be used to evaluate the Company's performance. The parties recommending an incentive mechanism have diverging views as to what the appropriate target should be. As described above, Public Counsel recommends that the appropriate target should be what PSE has referred to as their "stretch" target, which is 20 aMW for 2007. PSE and NWECA instead propose that what PSE has referred to as the "penalty threshold" should be the target, or 16.5 aMW for 2007.¹²⁶ Commission Staff recommends a baseline target of 18.3 aMW for 2007.¹²⁷

81. For several reasons, Public Counsel believes that PSE's "stretch" target, which has consistently been in the range of 20 aMW, is the appropriate target. As PSE's witness Mr. Shirley testified at hearing, this is the target that PSE reports to the Northwest Power and Conservation Council.¹²⁸ In addition, as Mr. Shirley also confirmed at hearing, the Company's annual budget for its energy efficiency programs is associated with an annual conservation target of 20 average megawatts (aMW)¹²⁹, not the 16.5 aMW "baseline" target as proposed by the Company and NWECA. The "stretch" target of approximately 20 aMW is also what PSE reported to its customers in their most recent conservation report to customers.¹³⁰ Consistent with the 2002 Conservation Settlement, PSE currently faces a potential penalty—granted, a much smaller penalty than proposed here—if they fail to achieve 33 aMW during the 2006-2007 period (or 16.5 aMW annually). This 16.5 aMW performance level has therefore been referred to as the

¹²⁶ Exh. No. 372, p. 9:1-3 (Shirley); Exh. No. 499, p. 7:13-14 (Glaser)

¹²⁷ Exh. No. 561, 31:10-32:16 (Steward).

¹²⁸ Shirley, Tr. 580:15-23.

¹²⁹ Shirley, Tr. 580:8-14. See also, Exh. No. 514.

¹³⁰ Exh. No. 414.

“penalty threshold,” as shown in PSE’s November 18, 2005 filing with the Commission regarding 2006-2007 conservation targets.¹³¹ Public Counsel believes that a “penalty threshold” is unacceptable as a measure for achievement for an incentive. The Company should be encouraged to continue to set its program budgets and conduct its cost-effectiveness analyses on its high, though potentially achievable targets. The culture of the Company should continue to focus on its higher goals, rather than shift its attention to its lower penalty targets.

V. DEPRECIATION TRACKER

A. PSE’s Depreciation Tracker Proposal.

82. PSE presents the depreciation tracker as designed to directly address a major cause of attrition facing the Company.¹³² In summary, PSE proposes that the increased expense associated with growth in depreciation for electric and natural gas transmission and distribution plant investment be recovered by means of a tracker mechanism and ultimately through a surcharge on PSE’s existing tariff schedules. The surcharge would be based on the incremental depreciation expense over that reflected in existing rates.¹³³

B. PSE’s Arguments For the Tracker are Not Persuasive.

83. The depreciation tracker violates fundamental principles of ratemaking. Energy utilities have traditionally been regulated based upon their cost to provide service, including an opportunity to earn a reasonable return on investment. These factors and the resulting revenue requirement are reviewed in a rate case, in which a balanced review of jurisdictional expenses, rate base investment, cost of capital, and revenue at present rates is undertaken at a common

¹³¹ Exh. No. 394.

¹³² Exh. No. 421, p. 66:16 – p. 67:8. (Story).

¹³³ Exh. No. 421, p. 67:17-p. 68:4 (Story).

point in time referred to as a “test period” or “test year.”¹³⁴ A synchronized review of these factors is essential due to the dynamic nature of utility costs and expenses. For example, in the instant case, PSE must account for its higher customer count and sales volumes and its current capital market conditions, at the same time as it seeks recognition of a larger rate base and increased depreciation expense.

84. A major problem with the use of a depreciation tracker, as with decoupling, is the potentially serious distortion of the “matching principle.”¹³⁵ Again, the matching principle recognizes the necessity of matching all revenues and costs (expenses, rate base, rate of return) at a consistent period of time to determine needed changes in utility pricing. *See, e.g., WUTC v. Avista Corporation*, Docket Nos. UE-050482, UG-050483, Order No. 05, ¶ 111. The depreciation tracker proposed by PSE in this case violates the matching principle. For these reasons, isolation of individual cost elements for recovery outside of test year ratemaking, so-called “single-issue ratemaking” is strongly disfavored.¹³⁶

1. Attrition.

85. PSE witness Story argues that regulatory lag and attrition create the need for the depreciation tracker when a utility is experiencing considerable growth or replacement of infrastructure.¹³⁷ In fact, utilities with considerable growth normally see accretion to earnings as margin contributions are added which recover fixed costs and overhead.¹³⁸ If attrition is

¹³⁴ Exh. No 506,, p. 4:5-11 (Brosch).

¹³⁵ Exh. No. 506 , pp. 11:19-12:6 (Brosch).

¹³⁶ Exh. No. 506, p. 14:3-14, (Brosch)

¹³⁷ Exh. No. 421, p. 66:18-p.67:16. (Story).

¹³⁸ Exh. No.506 , p. 23:11-18 (Brosch).

occurring in a period of growth, the solution lies in line extension policy or rate design, not in creating a new tracker mechanism.¹³⁹

86. While there is some surface appeal to the infrastructure replacement argument, the reality is that utility companies are continually retiring old plant and replacing new plant at what are generally higher replacement prices.¹⁴⁰ This activity is triggered by many factors including: the need to serve new customers, the need to expand capacity, the need to deal with leaks or excessive outage response costs, the replacement of worn out plant, the relocation of facilities for public improvements, replacement of plant that is not cost-effective to maintain, compliance with regulatory mandates, and installation of automation.¹⁴¹ If PSE's argument were correct, every utility in the country would need a rate increase every year to deal with this attrition phenomenon. While they undoubtedly would like such an increase, it is neither necessary financially, nor fair to ratepayers.

2. The depreciation tracker would distort test period relationships.

87. PSE proposes to include new electric and gas distribution plant investment in the depreciation tracker. All customers would pay the rates resulting from the tracker on new investments. Shareholders on the other hand would retain all revenues and margins resulting from the growth between test years since no tracker is put in place to account for the incremental profit margins from the new customers. This is patently not a fair result.¹⁴² The depreciation tracker purports to account for load growth, but does so only indirectly and ineffectively.¹⁴³

¹³⁹ *Id.*

¹⁴⁰ Exh. No.506 , p. 24:3-6 (Brosch); McLain, Tr. 192:13-23.

¹⁴¹ *Id.*, p. 24:6-14 (Brosch); McLain ,Tr. 192:24-193:2.

¹⁴² Exh. No. 506. , p. 26:7-13(Brosch).

¹⁴³ *Id.*, p. 26:13-18.

88. PSE was asked in discovery what capital investments it would not make if the depreciation tracker were not granted, assuming those investments were necessary and prudent.¹⁴⁴ PSE responded by saying that the date request misinterpreted the testimony and that the question is one of timing not of prudence.¹⁴⁵
89. Ms. McLain's attempts to create the impression that Commission ratemaking policy and decisions have prevented the Company from recovering its costs, and that this is a reason to approve the tracker.¹⁴⁶ On cross-examination, however, McLain agreed that PSE makes no assertion that the Commission denies PSE recovery of its prudently incurred costs, whether for depreciation, or any other expense. Its simply a matter of timing.¹⁴⁷
90. Likewise, Ms. McLains' written testimony asserts that if PSE is restricted from cost recovery, presumably by not getting approval of the depreciation tracker, it will have to "scale back" on planned investment, maintenance and inspections. On cross examination, however, she disclaimed any intent on the part of the Company to issue an ultimatum to the Commission that it would not make necessary investments unless the tracker was approved.¹⁴⁸

3. Incentive in regulatory lag would be disturbed.

91. Importantly, test year based ratemaking creates a significant incentive for utility management. By controlling and reducing costs between rate cases, the utility maximizes the opportunity to actually earn at or above the authorized rate of return established by the regulator. Shareholders are rewarded with higher earnings between test years. Conversely, unfavorable

¹⁴⁴ Exh. No. 249.

¹⁴⁵ *Id.*; Tr. 195-199.

¹⁴⁶ Exh. No. 245, p.2:10-15 (McLain).

¹⁴⁷ Tr. 200:16.

¹⁴⁸ Tr. 198:23-199:7.

changes such as cost increases can bring earnings below authorized levels. Management also has an incentive not to allow this to occur. Thus, so-called “regulatory lag” provides a symmetrical incentive to management.¹⁴⁹

92. If depreciation expense is tracked piecemeal between rate cases, the incentive to control the cost of capital expenditure is disturbed. PSE management would be likely to focus on other business issues and care less about stringent cost controls over capital expenditures that will simply be tracked into higher depreciation tracker levels that will be charged to customers.¹⁵⁰

4. New investments create operational efficiencies that reduce expenses.

93. There is another factor that is not reflected in the depreciation tracker. Many types of operations and maintenance (O&M) expenses are influenced by the age and condition of utility plant, for example: services calls for gas leaks, leak repair costs, systematic replacement of problem areas. In the case of electric facilities, replacement, restoration, undergrounding, and automation of plant can significantly affect staffing and O&M expenses. While PSE characterizes infrastructure investments as creating “financial pressures,”¹⁵¹ these expenditures are intended to efficiently serve new and existing customers, increase margin revenues, and control expense levels. In theory, a fairly designed tracker would include both the operational impacts of investment, as well as the depreciation expense. As a practical matter, actually designing a tracker to capture all of the complex impacts of an investment throughout the utility’s business operations is not feasible.¹⁵²

¹⁴⁹ Exh. No. 506 , p. 7:13-16 (Brosch).

¹⁵⁰ Exh. No.506, p. 27:4-10 (Brosch).

¹⁵¹ Exh. No. 421, p. 77:9-10 (Story).

¹⁵² Exh. No. 506, p. 29:3-6 (Brosch) .

5. Transmission and distribution depreciation expense is not completely beyond management control.

94. Significant capital investment is continuously required by utilities to replace, extend and modernize T&D facilities, as PSE witness McLain acknowledged at the hearing.¹⁵³ In fact, management has considerable discretion and control over the timing and cost levels of capital expenditures. Prudent management should be actively involved in facilities planning and design, construction workforce management, materials procurement, contractor bidding and administration, and other elements of capital expenditure optimization.¹⁵⁴

6. The depreciation tracker should be rejected.

95. The depreciation tracker introduces unfair imbalance into ratemaking. The attrition arguments are not persuasive or well supported. The investment and expenses that PSE cites are within the normal course of doing business for a utility company, and are largely within the control of management. There is no evidence that the Company is being denied recovery of prudently incurred costs, or that it will not be able to make necessary investments to provide service. The fact that the Company would like to accelerate the timing of its depreciation cost recovery is not a reason to impose this new burden on ratepayers.

VI. POWER COST ADJUSTMENT (PCA)

A. Summary of Recommendation.

96. Public Counsel, the Commission Staff, and ICNU are in agreement on this issue and have filed joint testimony with the Commission in this case.¹⁵⁵ The parties jointly recommend that the

¹⁵³ Tr. 192:13-23.

¹⁵⁴ Exh. No. 506TC, p. 29:17-p. 30:4 (Brosch).

¹⁵⁵ Exh. No. 599 (Lazar, Schoenbeck, Mariam).

current PSE Power Cost Adjustment mechanism remain basically unchanged. The dead band should remain at \$20 million and the sharing bands at the current levels of \$40 million and \$120 million. Power supply contracts should continue to be priced according to the current mechanism. Exhibit E should remain a part of the PCA mechanism. The joint parties do support one of PSE's recommendations --- inclusion of hedging expenses as an allowable cost within the PCA mechanism.¹⁵⁶

B. Background of the PCA Mechanism.

97. The joint testimony reviews the evolution of the current PCA mechanism. PSE has had a number of regulatory mechanisms to address variations in power costs, including the drought surcharges of 1980-81, the Energy Cost Adjustment Clause (ECAC) from 1982-88, the Periodic Rate Adjustment Mechanism (PRAM) from 1991-1996, and the current PCA from 2002 to the present.¹⁵⁷ The current PCA was established as part of the comprehensive settlement in the 2001 general rate case.¹⁵⁸

C. PSE's Proposed Changes to the PCA.

98. PSE proposes eliminating the deadband and imposing a smaller sharing requirement so that electric customers bear a larger share of the power cost risk. The Company proposes eliminating Exhibit E to the original PCA, which limits increases to power contracts from flowing through the PCA without a PCORC. In addition, the Company proposes adding a new category of allowable costs to the PCA – power supply hedging costs.

¹⁵⁶ *Id.*, Exh. No. 599, p.2:17-19.

¹⁵⁷ Exh. No. 599, pp. 4-7.

¹⁵⁸ *WUTC v. PSE*, UE-011570, UG-011571, Twelfth Supplemental Order, Ex. A to Settlement Stipulation.

D. The PCA is Working as Expected.

99. The PSE PCA was intended to protect shareholders from severe earnings attrition caused by power cost variations beyond the Company's control, to provide incentives for power supply cost control, and to provide relatively stable rates for consumers.¹⁵⁹

100. The PSE PCA was designed to place the Company at risk for only a portion of its power supply cost variations. This was done by limiting PSE's risk to only a fraction of its "retention" or "retained earnings" each year so that its ability to pay its dividend out of current earnings was not in jeopardy due to weather or power market variations.¹⁶⁰ The design has worked well. PSE's utility earnings have in fact been adequate to support the dividend since the PCA was adopted.¹⁶¹ As shown on Figure 2 of the joint testimony, earnings have consistently exceeded the \$1.00 dividend.¹⁶²

101. With regard to rate stability, while there have been increases due to PCORC filings and the 2004 general rate case, the PCA itself has not resulted in any rate increases for consumers because the variations in PSE's power supply costs have been small enough that the mechanism has not triggered an increase or a decrease. This is confirmation that the mechanism was well designed at its inception.

102. PSE attempts to support its position by setting forth the unrealistic, catastrophic scenario of power costs varying by \$120 million each year over a four-year period. Under these circumstances, PSE asserts that shareholders may be exposed to approximately \$152 million more in excess power costs without the cost cap.¹⁶³ The implausibility of PSE's example is

¹⁵⁹ *Id.*, p. 10:2-7.

¹⁶⁰ *Id.*, p. 10:10-12:22.

¹⁶¹ *Id.*, p.13:1-11.

¹⁶² *Id.*, p. 13.

¹⁶³ Exh. No. 14, p.4:6 – 5:3 (Aladin).

illustrated by the Company's own testimony, which reveals that the probability of PSE's catastrophic scenario actually occurring is extremely low.¹⁶⁴ Moreover, PSE fails to explain that the cost cap will play no role whatsoever in the more likely event that excess power costs do not exceed \$40 million. PSE Is In Much Better Financial Condition Than When The PCA Was Created.

103. PSE's PCA was adopted at a time when the Company faced financial challenges. The PCA was one of the tools agreed to in the 2002 settlement to improve PSE's financial strength.¹⁶⁵ Since the 2002 settlement, the Company's situation has improved markedly. PSE has significantly enhanced its equity ratio by issuance of new stock.

104. Figure 5 in the joint testimony reflects PSE's improved condition, showing a comparison of financial strength indicators and PCA exposure between 2001 and 2005, based on data from the Company's annual report. Electric revenues are up 32 percent, net income 46 percent, and shareholder equity 49 percent. At the same time, the risk exposure under the PCA has not changed at all in dollar terms. As a result, PSE's exposure under the mechanism is much smaller now than when the PCA was adopted.

105. PSE's proposed changes in the sharing band would reduce the Company's exposure to risk of earnings variations, shifting that risk to customers. If power costs increase \$200 million, for example, there would be a 40 percent decrease in risk to shareholders under the PSE proposal.¹⁶⁶ The columnar chart in Exh. No. attached to the joint testimony shows in more detail the effect of the proposed changes as compared to the current mechanism. Under the PSE

¹⁶⁴ *Id.*, p. 5:15 – 6:6; Exh. No.15.

¹⁶⁵ Exh. No.599, p. 17:4-18.

¹⁶⁶ Exh. No. 599, p. 19:8-17.

proposal, the maximum adverse impact is reduced by about one third (from 31 cents per share to 20 cents per share). Moreover, the range of risk is narrowed so that nearly all outcomes are within a range of only 15 cents per share, a risk reduction of over 50 percent.

106. PSE has made the assertion that the expiration of the \$40 million 4-year cap in the original PCA mechanism “results in a massive shift of exposure to PSE to absorb extreme power costs going forward unless changes are made to the existing PCA mechanism in this case.”¹⁶⁷ This is an attempt to create the false impression that the expiration of the cap is unexpected, unplanned, and unfair.

107. The 4-year cap was just that – a temporary measure. It was put in place because PSE had a weak capital structure at the time of the 2001 settlement. The parties agreed to the 4-year cap in conjunction with the equity tracking mechanism and penalties. During the settlement hearing for the original PCA, Staff witness Merton R. Lott explained: “The mechanism, as we designed it, was without the \$40 million cap, and the \$40 million cumulative cap was laid on top of it with an intent to help the Company achieve their equity ratios during that first four years.”¹⁶⁸

108. Customers therefore assumed more risk by capping the shareholders’ liability at \$40 million for a four-year period. However, the PCA itself was designed as a long-term mechanism that would continue after the cap expired, as evidenced by the fact that the sharing bands go up to \$120 million. The cap was always intended to be temporary and to expire once PSE had rebuilt its capital structure from 30% to 40% equity. At 40% equity PSE can absorb some earnings variation without undue risk to its credit rating. PSE has now rebuilt its equity to in

¹⁶⁷ Exh. No. 14, p.2:1-3 (Aladin)

¹⁶⁸ *Re PSE, WUTC*, Docket Nos. UE-011570 & UG-011571, Settlement Hearing Transcript at 2131:14-18 (Lott (June 17, 2002)).

excess of 40%. It is misleading and inaccurate of PSE to suggest that the expiration of the temporary cap shifts unanticipated risk to PSE when the expiration was intended and when the condition it was designed to remedy has been resolved.

E. The Financial Community Has Responded Positively to the Current PCA Mechanism.

109. The financial community has been very positive about the PCA mechanism. D.A. Davidson and Company, for example, comment on the value of the PCA mechanism, note the Commission Staff position on revenue requirement in this proceeding, and issue and reaffirm a “buy” rating on PSE stock.¹⁶⁹
110. The JP Morgan report predicted the PSE shares would trade lower as a result of the Staff revenue recommendation. In fact, PSE stock traded up.¹⁷⁰ The market is responding positively to the past actions this Commission has taken, including the currently-designed PCA mechanism.
111. Mr. Valdman has included numerous reports from the financial community in his Exhibit Nos. 455 and 459. One of the common threads of these is that measures that stabilize earnings are desirable, and reduce the perceived risk of the Company. The PCA is one of these mechanisms. It has worked to stabilize PSE’s earnings under the existing design. Notably, Mr. Valdman has not acknowledged the tremendous benefit that the existing PCA provides, nor has he quantified the additional value that the Company’s proposed changes to the PCA, the proposed decoupling mechanism, or the proposed depreciation tracking mechanism would all provide. Instead he takes care to base his opinions only on the required return for PSE on its existing regulatory framework, while asking the Commission to weaken the ratepayer protections currently in place, without any compromise on either capital structure or rate of return.

F. Except for Hedging Expense, PSE's Proposed Changes to the PCA Should Be Rejected.

1. Hedging expense should be allowed in the PCA.

112. The joint parties support PSE's proposal to include hedging costs as allowable PCA expense. Hedging manages the specific costs which the PCA is designed to track, and if successful will ultimately reduce fuel expenses. It is reasonable, therefore, to include hedging expense in the PCA mechanism. It should be noted, however, that hedging further enhances the risk reduction caused by the PCA. The inclusion of hedging should be reflected in a further downward adjustment in the cost of capital.¹⁷¹

113. PSE's other proposed changes ignore the fact that the Company is far better situated to manage power cost risk than are its individual customers. It can manage risk by buying long-term fixed price resources, favorable structuring of power purchase contracts, hedging fuel costs, and minimizing down time on its own power plants.¹⁷²

2. The "Exhibit E" component of the PCA should be retained.

114. PSE proposes, *inter alia*, to eliminate "Exhibit E," a component of the PCA 2002 settlement which addresses contracts. The PSE proposal would allow any increase in the contract price to be included in the PCA. This is an unreasonable approach. As the joint testimony explains, Exhibit E was part of a balanced compromise in the original PCA. Under the

¹⁶⁹ Exh. No. 459, pp. 10, 29 (Valdman); Valdman, Tr. 247:6-248:1

¹⁷⁰ Valdman, Tr. 246:6-10.

¹⁷¹ Exh. No. 599, p.21:14-22:3; No specific reduction due to hedging is recommended in the joint testimony because it is anticipated that PSE will be filing another general rate case within the next 18 months.

¹⁷² *Id.*, p.22:5-22.

compromise, PSE's allowed contract cost recovery was capped in return for allowing other costs to rise between rate cases, such as those included in a PCORC.¹⁷³

3. PSE's proposals are not consistent with the guidance on PCAs provided in the 2006 PacifiCorp rate case order.

115. The Commission has stated that a "properly designed" PCA should allow ratepayers to "receive the benefit of a reduction in cost of capital, as a power cost adjustment introduces rate instability for ratepayers and earnings stability for stockholders."¹⁷⁴ The amount of risk apportioned by a PCA is one of the most important factors that the Commission considers when deciding whether a reduction in the cost of capital is warranted.¹⁷⁵ The Commission has recognized deadbands and sharing bands as "useful mechanisms, not only to allocate risk, but to motivate management to effectively manage or even reduce power costs."¹⁷⁶

116. Contrary to the Commission's guidelines, PSE proposes to eliminate the deadband and narrow the sharing bands. Not only would such changes shift more risk to customers despite PSE's improved financial condition, but they would also provide little incentive for the Company to efficiently manage its power costs. The Commission recently rejected PacifiCorp's proposed PCA mechanism based partly on the fact that it lacked a deadband.¹⁷⁷

117. At the same time as it proposes eliminating the deadband, PSE proposes sharing bands that would significantly increase customers' risk. PSE's proposal would force customers to assume 50% of *any* power cost variations up to \$25 million, 90% of any variations over \$25

¹⁷³ *Id.*, 22:12-23:16.

¹⁷⁴ *Re PacifiCorp*, WUTC Docket No. UE-050684, Order No. 4 at ¶¶ 91 (Apr. 17, 2006).

¹⁷⁵ *Id.* at ¶ 97.

¹⁷⁶ *Id.* at ¶ 96.

¹⁷⁷ *Id.* at ¶ 99.

million, and 95% of any variations over \$120 million.¹⁷⁸ The Company, however, is in a much better position than customers to manage this risk. The Company justifies its proposed sharing bands based on the assertion that PSE cannot control hydro risk.¹⁷⁹ Although hydro risk is indeed variable, the current PCA adequately addresses this risk by providing for deferral and amortization of hydro variations.¹⁸⁰ Additionally, PSE can take steps to address this risk, such as choosing less volatile resources and using fuel hedging.¹⁸¹

118. Furthermore, in the Company's latest PCA Annual Report, PSE reported that its actual power costs were approximately \$10.5 million below projections.¹⁸² As of June 30, 2006, the deferral balance under the PCA mechanism had only reached \$6.2 million.¹⁸³ The deferral balance must reach a "trigger point" of \$30 million before PSE is allowed to request a rate adjustment, an amount that was determined not to put PSE at financial risk.¹⁸⁴ Due to the minimal deferral balance that has accrued during the life of the PCA despite the fact that four of the last five years have had below normal hydro, PSE cannot assert that the current PCA design places a disproportional amount of risk on the Company.

119. PSE's proposal also shifts more risk to customers without accounting for any corresponding compensating benefits to customers. Astonishingly, PSE actually proposes a higher return on equity and a higher equity ratio.¹⁸⁵ Without such evidence, the Commission and

¹⁷⁸ Exh. No. 11C, p. 20:1-3 (Aladin).

¹⁷⁹ *Id.* at 21:5-7.

¹⁸⁰ Exh. No. 599, p.23:20 – 24:5 (Joint PCA).

¹⁸¹ *Id.*, p. 24:7-14.

¹⁸² *Re PSE 2006 PCA Report*, WUTC Docket No. UE-061410, Petition of PSE for Approval of its 2006 PCA Mechanism Annual Report at ¶ 8 (Aug. 31, 2006).

¹⁸³ *Id.* at ¶ 10.

¹⁸⁴ Exh. No. 599 at 12:1-3 (Joint Testimony).

¹⁸⁵ *Id.* at 25:17-20.

the parties to this proceeding lack sufficient information to fully evaluate PSE's proposed changes.¹⁸⁶ Ultimately, the Commission should leave the PCA as is to ensure that the Company has an incentive to minimize power costs and to ensure an appropriate balance of risk between shareholders and customers.

4. The recent Avista ERM order provides a useful comparison.

120. The Commission recently approved modifications to Avista Energy Recovery Mechanism (ERM), a form of PCA. The joint testimony presents a comparison between the ERM and PSE's PCA.¹⁸⁷ Measured on a revenue basis, PSE's mechanism has a somewhat lower level of risk than Avista's. Measured on an earning's basis, PSE has a slightly higher risk level for shareholders. Overall the current PSE PCA exposes Puget shareholders to a comparable level of risk to the modified Avista ERM.

G. If PCA Changes Are Made They Should Reflect PSE's Healthier Financial Condition.

121. As argued above, the PCA changes recommended by PSE are not appropriate. The PCA is essentially working as planned and need not be modified at this time, except as to hedging costs. If the Commission were to consider changes of any kind to update the PCA, they should reflect the fact that PSE is a larger and financially healthier utility than when the PCA was adopted. The joint testimony recommends a methodology for updating the dead band and sharing bands to reflect PSE's financial situation.¹⁸⁸

¹⁸⁶ See *WUTC v. Avista*, WUTC Docket Nos. UE-050482 and UG-050483, Order No. 5 at ¶¶ 67, 71 (Dec. 21, 2005) (finding an insufficient record to authorize a change in the deadband where Avista failed to account for any compensating benefit to customers).

¹⁸⁷ Exh. No. 599, pp. 14-16.

¹⁸⁸ Exh. No. 599, pp. 26-28.

122. Using financial indicators, at Figure 8 of the joint testimony,¹⁸⁹ the parties show that updates to the PCA would result in the dead band increasing to \$25 million, the 50 percent band increasing to \$50 million, the 90 percent band to \$100 million, the 95 percent band moving up to costs over \$150 million. The trigger would increase to \$40 million. At this time, the joint parties do not recommend adoption of these modifications. Instead, the Commission should direct a study of the financial risks posed by power costs under the current PCA from the date of inception to the present. The study should be presented to the Commission by the Company at least three months prior to filing its next general rate case. This would be a predicate to updating the sharing bands and trigger threshold. Any changes in the PCA should be deferred until that study is completed and reviewed in the next general rate case.¹⁹⁰ Until then, the Commission should allow the current PCA to continue to operate as it was designed.

VII. COST OF CAPITAL

A. PSE's Cost of Capital Request Is Not Reasonable.

123. While Public Counsel has not presented a cost of capital witness in this case, the issue is nonetheless an important one from the consumer perspective. Public Counsel believes the cost of capital recommendations of Staff's witness Steve Hill and ICNU witness Gorman are in a far more reasonable range than the request of PSE. Without commenting on the more technical analyses offered by the experts, a number of observations can be made.

124. PSE's suggestion that its return on equity (ROE) should be 11.25¹⁹¹ is simply extreme. Even without engaging in technical cost of capital analysis, numerous common sense factors

¹⁸⁹ Exh. No. 599, p. 28.

¹⁹⁰ *Id.*

¹⁹¹ Exh. No. 301, p.15:15 (Morin)

indicate that their request is outside any reasonable range. This Commission has not set ROE above 11 percent for any Washington energy Company in a number of years. It recently indicated that the proper ROE for an all-electric regulated utility in Washington, PacifiCorp, was 10.2 percent.¹⁹² PacifiCorp does not have gas operations that lower its risk, nor does it have a PCA or PCORC mechanism that do likewise, as PSE does. If anything, PSE's correct ROE level might reasonably be expected to be below that of PacifiCorp. It is difficult to imagine that PSE's ROE should really exceed PacifiCorp's by 105 basis points.

125. PSE's stock price has remained at least steady since the last rate case. Indeed, during this rate case, PSE has outperformed the S&P.¹⁹³ PSE litigated cost of capital quite recently in its 2004 rate case and the Commission set the shareholder profit rate at 10.3 percent.¹⁹⁴

126. Public Counsel does not suggest that these factors can be used simplistically to set PSE's cost of capital. Each company is different. Each is subject to different risks, and has a different capital structure. Wall Street analysts should not be allowed to dictate ROE levels. Nevertheless, these factors do provide some sense of a "reality check" as to the reasonable expectations for current cost of capital in Washington. Given these factors, it is appropriate to ask why PSE would choose to present such an untenable position. Perhaps the purpose of such a filing is to "raise the average" by setting a high top end such that a midpoint compromise is higher. The Commission should resist such any such attempt to manipulate this issue. If the Commission is developing a range within which to set ROE, it should be a range of reasonableness, not one skewed by unrealistic and extreme requests.

¹⁹² PacifiCorp order, ¶ 264.

¹⁹³ Exn. No. 599, p. 20:8-13.

¹⁹⁴ *WUTC v. PSE*, Docket Nos. UG-040640, UE-040641, Order No. 06.

B. PSE's ROE Request is Inconsistent With its Simultaneous Request for Significant Risk Reduction Mechanisms.

127. PSE's requested ROE appears even more unfounded in light of the fact that the Company is seeking three different risk reduction mechanisms in this case that shift risk to ratepayers and away from shareholders: a decoupling mechanism, a depreciation tracker, and modifications to the PCA. There is a serious disconnect between asking for such significant risk reduction while simultaneously asking, not just to maintain current ROE, but to increase it by more than a percentage point.

128. PSE's approach flies directly in the face of clear guidance from the Commission on the cost of capital effects of decoupling and PCA mechanisms. The need for cost of capital reductions to accompany risk shifting mechanisms is no longer a matter of debate in Washington.

VIII. SETTLEMENTS ON OTHER ISSUES

A. Electric Rate Spread and Rate Design.

129. As one of the signatories, Public Counsel supports the electric rate spread and rate design settlement between the parties and PSE. The joint testimony establishes that settlement is a fair and comprehensive resolution of these issues.¹⁹⁵

B. Gas Rate Spread and Rate Design.

130. Public Counsel joins in the gas rate spread and rate design settlement.¹⁹⁶ This brief supports and incorporates by reference the arguments made by Staff in its brief on this issue.

¹⁹⁵ Exh. Nos. 2, 3.

¹⁹⁶ Exh. Nos. 581-587

C. Power Costs.

Public Counsel has a joint position with Staff and ICNU on power costs and participated in the joint testimony on that issue.¹⁹⁷ Public Counsel adopts the ICNU brief on this issue.

D. Revenue Requirement

131. Public Counsel did not present any revenue requirement witnesses. Public Counsel does not take a position on the revenue requirement stipulation filed by PSE and Staff.

IX. CONCLUSION

132. For the reasons discussed in this brief, Public Counsel asks the Commission to reject the decoupling proposals of PSE and the other parties and to direct the parties to pursue a gas incentive mechanism. The Commission should reject the depreciation tracker and the Company's PCA modifications.

133. Public Counsel urges the Commission to accept an electric conservation incentive mechanism in the form proposed by Public Counsel, and to adopt the settlement proposals of the parties on other issues.

134. DATED this 31st day of October, 2006.

ROB McKENNA
Attorney General

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Summary of ATMOS CUA Revenue - Public Authority Revenue

CAPD Exhibit MDC C 6

Q. 73 Projections

Line No.	Year	Avg. Rev./ Customer*	Avg. Cust. **	Rev./ Customer		Diff. \$	Proj. Avg. Cust.	Projected CUA True-Up Revenue	Projected Public Authority Revenues	Total Projected Revenue	Revenue In Excess of Benchmark
				Bench. Year \$	Proj. Year \$						
Column		(a)	(b)	©	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	Benchmark***	380.20	496						\$ 188,483	\$ 188,483	
2	Proj. Year 1	374.12	506 (	380.20 -	374.12)	6.08 *	506 =	\$ 3,077	\$ 189,365	\$ 192,442	
3			Annual Growth						881		
4			Revenue in excess of Benchark								\$ 3,958
5	Proj. Year 2	372.97	517 (	380.20 -	372.97)	7.22 *	517 =	\$ 3,733	\$ 192,750	\$ 196,483	
6			Annual Growth						3,385		
7			Revenue in excess of Benchark								\$ 7,999
8	Proj. Year 3	371.76	528 (	380.20 -	371.76)	8.44 *	528 =	\$ 4,452	\$ 196,157	\$ 200,609	
9			Annual Growth						3,408		
10			Revenue in excess of Benchark								\$ 12,126
11	Proj. Year 4	370.38	539 (	380.20 -	370.38)	9.82 *	539 =	\$ 5,289	\$ 199,533	\$ 204,822	
12			Annual Growth						3,375		
13			Revenue in excess of Benchark								\$ 16,338

Source Data (ATMOS response in CAPD Data Request #1, Q.73) discussion w/McCormac/Cagle

*= Revenue per customer : customer growth factor of 2.1%/Yr; Usage Factor -1.5%

**= customer growth factor @2.1%

** Benchmark Source ATMOS PJC-1

Rev.	Mo. Rev.	(m)	(n)
1,097			
27,227			
38,325			
Ann. Cust.	Aug. Mo. Rev. Cust.	Aug. Mo. Tr.	Aug. Mo. Tr.
1,076	89.85		
36,357	3029.79		
37,436			
Ann. Cust.	Aug. Mo. Rev. Cust.	Aug. Mo. Tr.	Aug. Mo. Tr.
1,064	88.63		
35,690	2974.19		
36,754			
Ann. Cust.	Aug. Mo. Rev. Cust.	Aug. Mo. Tr.	Aug. Mo. Tr.
1,053	87.74		
35,208	2933.98		
36,261			
Ann. Cust.	Aug. Mo. Rev. Cust.	Aug. Mo. Tr.	Aug. Mo. Tr.
1,049	87.39		
35,015	2917.51		
36,064			

Summary of ATMOS CUA Revenue - Commercial Revenue

CAPD Exhibit MDC C 4

Q. 73 Projections

Line No.	Year	Avg. Rev./ Customer*	Avg. Cust. **	Rev./ Customer		Diff. \$	Proj. Avg. Cust.	Projected CUA True-Up Revenue	Projected Commercial Revenues	Total Projected Revenue	Revenue In Excess of Benchmark
				Bench. Year \$	Proj. Year \$						
Colmun		(a)	(b)	©	(d)	(e)	(f)	(g)	(h)	(i)	(j)
1	Benchmark***	1,111.62	15,052						\$ 16,732,403	\$ 16,732,403	
2	Proj. Year 1	1,092.12	15,368 (	1,111.62 -	1,092.12)	19.50 *	15,368 =	\$ 299,699	\$ 16,784,084	\$ 17,083,783	
3			Annual Growth						51,681		
4			Revenue in excess of Benchark								\$ 351,380
5	Proj. Year 2	1,077.16	15,691 (	1,111.62 -	1,077.16)	34.46 *	15,691 =	\$ 540,711	\$ 16,901,831	\$ 17,442,543	
6			Annual Growth						117,747		
7			Revenue in excess of Benchark								\$ 710,140
8	Proj. Year 3	1,066.34	16,021 (	1,111.62 -	1,066.34)	45.28 *	16,021 =	\$ 725,372	\$ 17,083,465	\$ 17,808,836	
9			Annual Growth						181,633		
10			Revenue in excess of Benchark								\$ 1,076,433
11	Proj. Year 4	1,062.02	16,357 (	1,111.62 -	1,062.02)	49.60 *	16,357 =	\$ 811,306	\$ 17,371,515	\$ 18,182,822	
12			Annual Growth						288,051		
13			Revenue in excess of Benchark								\$ 1,450,419

Source Data (ATMOS response in CAPD Data Request #1, Q.73) and discussions w/McCormac/Cagle

*= Revenue per customer : customer growth factor of 2.1%/Yr; Usage Factor -1.5%

**= customer growth factor @2.1%

** Benchmark Source ATMOS PJC-1

CAPD Exhibit MDC C 3

Q. 73 Projections

Customer Growth Factor = 2.1%

* Projected Using an annual 1.5% reduction in usage and 2.1% increase in customer growth

***Benchmark Data Source, ATMOS Ex. PJC-1

Summary of ATMOS CUA Revenue - Residential Revenue

CAPD Exhibit MDC C 2

Q. 73 Projections

Line Number	Year	Avg. Rev./ Customer*	Avg. Cust. **	Rev./ Customer		Diff. \$	Proj. Avg. Cust.	Projected CUA True-Up Revenue	Projected Residential Revenues	Total Projected Revenue w/CUA	Revenue In Excess of Benchmark
				Bench. Year \$	Proj. Year \$						
Column	(a)	(b)	©	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
1	Benchmark***	251.11	114,152						\$ 28,664,770	\$ 28,664,770	
2	Proj. Year 1	248.26	116,549 (	251.11 -	248.26)	2.85 *	116,549 =	\$ 332,458	\$ 28,934,272	\$ 29,266,730	
3			Annual Growth						269,502		
4			Revenue in excess of Benchark								\$ 601,960
5	Proj. Year 2	246.07	118,997 (	251.11 -	246.07)	5.04 *	118,997 =	\$ 599,814	\$ 29,281,517	\$ 29,881,331	
6			Annual Growth						347,245		
7			Revenue in excess of Benchark								\$ 1,216,561
8	Proj. Year 3	244.49	121,495 (	251.11 -	244.49)	6.62 *	121,495 =	\$ 804,659	\$ 29,704,181	\$ 30,508,839	
9			Annual Growth						422,663		
10			Revenue in excess of Benchark								\$ 1,844,069
11	Proj. Year 4	243.46	124,047 (	251.11 -	243.46)	7.65 *	124,047 =	\$ 949,539	\$ 30,199,985	\$ 31,149,525	
12			Annual Growth						495,805		
13			Revenue in excess of Benchark								\$ 2,484,755

Source Data (ATMOS response in CAPD Data Request #1, Q.73) and discussion with McCormac/Cagle

*= Revenue per customer: customer growth factor of 2.1

/Yr; Usage Factor of - 1.5%

**= customer growth factor @2.1%

** Benchmark Source ATMOS PJC-1

SUMMARY OF CALCULATED DECOUPLING REVENUE

CAPD Exhibit MDC C 1

ATMOS ENERGY CORPORATION
07-00105

Line Number	Billing Period (year)	Residential	Commercial	Public Authority	Total
Column	(a)	(b)	©	(d)	(e)
1	Benchmark Revenue	\$ 28,664,770	\$ 16,732,403	\$ 188,483	\$ 45,585,656
CUA Rider Additional Revenues					
2	Proj. Year 1 (CUA Revenue)	\$ 332,458	\$ 299,699	\$ 3,077	\$ 635,234
3	Annual Growth	269,502	51,681	881	322,065
4	Revenue in Excess of Benchmark	601,960	351,380	3,958	957,299
5	Requested Increase	5,804,596	3,395,010	47,196	9,246,802
6	Return on Rate Base	n/a	n/a	n/a	
7	Proj. Year 2 (CUA Revenue)	\$ 599,814	\$ 540,711	\$ 3,733	\$ 1,144,258
8	Annual Growth	347,245	117,747	3,385	468,378
9	Accumulated Growth	616,748	169,429	4,266	790,442
10	Revenue in Excess of Benchmark	1,216,561	710,140	7,999	1,934,701
11	Requested Increase	5,804,596	3,395,010	47,196	9,246,802
12	Return on Rate Base	n/a	n/a	n/a	
13	Proj. Year 3 (CUA Revenue)	\$ 804,659	\$ 725,372	\$ 4,452	\$ 1,534,482
14	Annual Growth	422,663	181,633	3,408	607,704
15	Accumulated Growth	1,039,411	351,062	7,674	1,398,147
16	Revenue in Excess of Benchmark	1,844,069	1,076,433	12,126	2,932,628
17	Requested Increase	5,804,596	3,395,010	47,196	9,246,802
	Return on Rate Base	n/a	n/a	n/a	n/a
18	Proj. Year 4 (CUA Revenue)	\$ 949,539	\$ 811,306	\$ 5,289	\$ 1,766,135
19	Annual Growth	495,805	288,051	3,375	787,231
20	Accumulated Growth	1,535,216	639,113	11,049	2,185,378
21	Revenue in Excess of Benchmark	2,484,755	1,450,419	16,338	3,951,512
22	Requested Increase	5,804,596	3,395,010	47,196	9,246,802
23	Return on Rate Base	n/a	n/a	n/a	n/a

Analysis of Current And Projected * Public Authority Revenue ATMOS Energy

CAPD Exhibit MDC C 7

Q. 73 Projections

		Customer Growth Factor = Reduction in Usage Factor =		2.1%			Increase In Usage (ccf) New cust. (year 1)	Increase In Usage (ccf) New cust. (Full Year)	Reduction In Usage (ccf) @ 1.5%	-1.5%	Proposed Rates Mo. Cust Commodity Chg./Ccf		Cust. Chg. Revenues	Com. Chg.		Avg. Rev. Per Cust.	Mo. Rev. Per Cust.	Allocated True-up Rev.	
Line No.	Benchmark Year***	Customers	Annual Customer Growth	Annual Use Per Customer							Ccf	Mo. Cust Chg.	Commodity Chg./Ccf			Total			
Column		(a)	(b)	©	(d)	(e)	(f)				(g)	(h)	(i)	(j)	(k)	(l)	(m)	(n)	(o)
1	225 PAG SR CIT SUMMER	74			45.1757						3,343	0.00	0.1838	-	614.44	614	100	8	
2	225 PAG SR CIT WINTER (weather sensitive)	104			157.2308						16,352	0.00	0.1838	-	3,005.50	3,005	15,656	1,305	
3	225 PAG GS - SUMMER	2,401			45.0208						108,095	10.00	0.1838	24,010	19,867.86	43,878	15,405	1,284	
4	225 PAG GS - WINTER (weather sensitive)	3,370			156.8852						528,703	13.00	0.1838	43,810	97,175.61	140,986	27,456	2,288	
5	Total Public Authority	5,949									656,493			67,820	120,663.41	188,483	58,616		
6	Avg. Customers	496												36%	64%	380.20			
7	Revenue/customer																		
Year 1		Customers	Annual Customer Growth	Annual Use Per Customer Red. @ 1.5%	Customer Growth Increase In Usage (ccf) New cust. (year 1)		Increase In Usage (ccf) New cust. (Full Year)	Reduction In Usage (ccf) @ 1.5%			Ccf	Mo. Cust Chg.	Commodity Chg./Ccf	Cust. Chg. Revenues	Com. Chg.	Total	Avg. Rev. Per Cust.	Mo. Rev. Per Cust.	Allocated True-up Rev.
8	225 PAG SR CIT SUMMER	76	2	44.4980		35	0	(50)			3,328	0.00	0.1838	-	611.68	612	97	8	15.67
9	225 PAG SR CIT WINTER (weather sensitive)	106	2	154.8723		172	0	(245)			16,278	0.00	0.1838	-	2,991.97	2,992	15,729	1,311	76.64
10	225 PAG GS - SUMMER	2,451	50	44.3455		1,135	0	(1,621)			107,609	10.00	0.1838	24,514	19,778.46	44,293	15,480	1,290	506.63
11	225 PAG GS - WINTER (weather sensitive)	3,441	71	154.5319		5,551	0	(7,931)			526,324	13.00	0.1838	44,730	96,738.32	141,468	27,569	2,297	2,477.98
12	Total	6,074									653,539			69,244	120,120.43	189,365	58,876		3,076.92
13	Avg. Customers	506												37%	63%	374.12			
14	Revenue/customer																		
Year 2		Customers	Annual Customer Growth	Annual Use Per Customer Red. @ 1.5%	Customer Growth Increase In Usage (ccf) New cust. (year 1)		Increase In Usage (ccf) New cust. (Full Year)	Reduction In Usage (ccf) @ 1.5%			Ccf	Mo. Cust Chg.	Commodity Chg./Ccf	Cust. Chg. Revenues	Com. Chg.	Total	Avg. Rev. Per Cust.	Mo. Rev. Per Cust.	Allocated True-up Rev.
15	225 PAG SR CIT SUMMER	77	2	43.8306		35	68	(50)			3,381	0.00	0.1838	-	621.51	622	97	8	19.01
16	225 PAG SR CIT WINTER (weather sensitive)	108	2	152.5492		173	333	(244)			16,540	0.00	0.1838	-	3,040.07	3,040	16,011	1,334	92.99
17	225 PAG GS - SUMMER	2,503	51	43.6803		1,141	2,202	(1,614)			109,338	10.00	0.1838	25,029	20,096.38	45,125	15,757	1,313	614.69
18	225 PAG GS - WINTER (weather sensitive)	3,513	72	152.2139		5,583	10,772	(7,895)			534,784	13.00	0.1838	45,669	98,293.32	143,963	28,059	2,338	3,006.52
19	Total	6,201									664,044			70,698	122,051.27	192,750	59,924		3,733.22
20	Avg. Customers	517												37%	63%	372.97			
21	Revenue/customer																		
Year 3		Customers	Annual Customer Growth	Annual Use Per Customer Red. @ 1.5%	Customer Growth Increase In Usage (ccf) New cust. (year 1)		Increase In Usage (ccf) New cust. (Full Year)	Reduction In Usage (ccf) @ 1.5%			Ccf	Mo. Cust Chg.	Commodity Chg./Ccf	Cust. Chg. Revenues	Com. Chg.	Total	Avg. Rev. Per Cust.	Mo. Rev. Per Cust.	Allocated True-up Rev.
22	225 PAG SR CIT SUMMER	79	2	43.1731		36	68	(51)			3,435	0.00	0.1838	-	631.30	631	96	8	23
23	225 PAG SR CIT WINTER (weather sensitive)	111	2	150.2610		174	335	(248)			16,801	0.00	0.1838	-	3,087.97	3,088	16,294	1,358	111
24	225 PAG GS - SUMMER	2,555	53	43.0251		1,148	2,215	(1,640)			111,061	10.00	0.1838	25,555	20,413.03	45,968	16,037	1,336	733
25	225 PAG GS - WINTER (weather sensitive)	3,587	74	149.9307		5,615	10,833	(8,022)			543,210	13.00	0.1838	46,628	99,842.08	146,470	28,552	2,379	3,585
26	Total	6,332									674,507			72,183	123,974.38	196,157	60,979		4,452
27	Avg. Customers	528												37%	63%	371.76			
28	Revenue/customer																		
Year 4		Customers	Annual Customer Growth	Annual Use Per Customer Red. @ 1.5%	Customer Growth Increase In Usage (ccf) New cust. (year 1)		Increase In Usage (ccf) New cust. (Full Year)	Reduction In Usage (ccf) @ 1.5%			Ccf	Mo. Cust Chg.	Commodity Chg./Ccf	Cust. Chg. Revenues	Com. Chg.	Total	Avg. Rev. Per Cust.	Mo. Rev. Per Cust.	Allocated True-up Rev.
29	225 PAG SR CIT SUMMER	80	2	42.5255		36	69	(52)			3,486	0.00	0.1838	-	640.77	641	96	8	27
30	225 PAG SR CIT WINTER (weather sensitive)	113	2	148.0071		175	337	(252)			17,053	0.00	0.1838	-	3,134.29	3,134	16,574	1,381	132
31	225 PAG GS - SUMMER	2,609	54	42.3797		1,154	2,228	(1,666)			112,727	10.00	0.1838	26,091	20,719.22	46,810	16,313	1,359	871
32	225 PAG GS - WINTER (weather sensitive)	3,662	75	147.6817		5,647	10,895	(8,148)			551,359	13.00	0.1838	47,608	101,339.71	148,947	29,040	2,420	4,259
33	Total	6,465									684,625			73,699	125,833.99	199,533	62,023		5,289
34	Avg. Customers	539												37%	63%	370.38			
	Revenue/customer																		

* Projected Using an annual 1.5% reduction in usage and 2.1% increase in customer growth

***Benchmark Data Source, ATMOS Ex. PJC-1

Atmos Energy Corporation
Exhibit PJ-1

	Rates effective Dec05		Adjusted Base Count	Adjusted Volumes Ccf	Current Adjusted Margin Rev	Proposed Rates		Total Revenues	Increase	Percent Change
	Monthly Customer chg	Commodity Charge/Ccf				Monthly Customer chg	Commodity Charge/Ccf			
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(k)	(j)	(m)
<u>RESIDENTIAL</u>										
210 RGS SUMMER	\$9.00	\$ 0.1207	548,615	7,271,449	\$ 5,815,200	\$ 10.00	\$ 0.1838	\$ 6,822,543	\$ 1,007,444	17%
210 RGS WINTER (weather sensitive)	12.00	\$ 0.1207	780,081	81,530,635	\$ 16,787,721	\$ 13.00	\$ 0.1838	\$ 21,450,385	\$ 4,662,664	28%
210 RGS SR CIT SUMMER	0.00	\$ 0.1207	16,367	224,390	\$ 27,144	-	\$ 0.1838	\$ 41,335	\$ 14,191	52%
210 RGS SR CIT WINTER (weather sensitive)	0.00	\$ 0.1207	24,159	1,906,468	\$ 230,111	-	\$ 0.1838	\$ 350,409	\$ 120,298	52%
211 HVAC	9.00	\$ 0.0667	25	4,295	\$ 511	\$ 9.00	\$ 0.0667	\$ 511	-	0%
Total Residential			1,369,847	70,337,726	\$ 22,860,886			\$ 28,665,283	\$ 5,804,396	25%
Avg. Residential Customer			12	621	\$ 204			\$ 255	\$ 51	25%
<u>COMMERCIAL</u>										
211 HVAC	9.00	\$ 0.0667	5	76	\$ 50	\$ 9.00	\$ 0.0667	\$ 50	-	0%
220 COM/IND GS (weather sensitive)	24.00	\$ 0.1851	180,556	47,674,861	\$ 13,157,953	\$ 27.50	\$ 0.2422	\$ 16,512,133	\$ 3,354,179	25%
230 LRG COM/IND GS (weather sensitive)	200.00	\$ 0.1966	71	948,718	\$ 200,718	\$ 200.00	\$ 0.2172	\$ 220,282	\$ 19,564	10%
250 OPT GS	310.00		39	0	\$ 12,090	\$ 310.00		\$ 12,090	-	0%
Block 1 Volumes		\$ 0.0901	0	631,610	\$ 58,908		\$ 0.1038	\$ 65,561	\$ 6,653	15%
Block 2 Volumes		\$ 0.0576	0	748,095	\$ 43,080		\$ 0.0713	\$ 53,339	\$ 10,259	24%
Block 3 Volumes		\$ 0.0234	0	0	\$ -		\$ 0.0371	\$ -	-	N/A
293 LRG TOWN HVAC GS	25.00		12	0	\$ 300	\$ 25.00		\$ 300	-	0%
Block 1 Volumes		\$ 0.0901	0	159,982	\$ 14,414		\$ 0.1038	\$ 16,606	\$ 2,192	15%
Block 2 Volumes		\$ 0.0576	0	14,088	\$ 811		\$ 0.0713	\$ 1,004	\$ 193	24%
Block 3 Volumes		\$ 0.0234	0	0	\$ -		\$ 0.0371	\$ -	-	N/A
Total Commercial			180,683	50,177,420	\$ 13,486,336			\$ 16,381,345	\$ 3,395,010	25%
<u>INDUSTRIAL</u>										
220 COM/IND GS	24.00	\$ 0.1851	3,409	5,358,946	\$ 1,073,757	\$ 24.00	\$ 0.2422	\$ 1,379,753	\$ 305,996	28%
230 LRG COM/IND GS	200.00	\$ 0.1966	195	2,082,856	\$ 450,455	\$ 200.00	\$ 0.2172	\$ 493,568	\$ 43,113	10%
240 DEMAND/COMM GS	310.00		12	0	\$ 3,720	\$ 310.00		\$ 3,720	-	0%
Block 1 Volumes		\$ 0.0901	0	240,000	\$ 21,824		\$ 0.1038	\$ 24,912	\$ 3,088	15%
Block 2 Volumes		\$ 0.0576	0	403,380	\$ 23,235		\$ 0.0713	\$ 28,761	\$ 5,526	24%
Block 3 Volumes		\$ 0.0234	0	0	\$ -		\$ 0.0371	\$ -	-	N/A
Demand Volumes		\$ 1.6293	0	40,596	\$ 86,143		\$ 1.6293	\$ 66,143	-	0%
250 OPT GS	310.00		565	0	\$ 175,066	\$ 310.00		\$ 175,066	-	0%
Block 1 Volumes		\$ 0.0901	0	6,087,350	\$ 548,470		\$ 0.1038	\$ 631,867	\$ 83,397	15%
Block 2 Volumes		\$ 0.0576	0	6,157,590	\$ 354,577		\$ 0.0713	\$ 438,036	\$ 84,359	24%
Block 3 Volumes		\$ 0.0234	0	0	\$ -		\$ 0.0371	\$ -	-	N/A
280 - ECONOMIC OEV GS (250 OPT)	310.00		13	0	\$ 4,030	\$ 310.00		\$ 4,030	-	0%
Block 1 Volumes		\$ 0.0675	0	260,000	\$ 17,550		\$ 0.0779	\$ 20,241	\$ 2,691	15%
Block 2 Volumes		\$ 0.0432	0	1,845,770	\$ 79,737		\$ 0.0535	\$ 98,703	\$ 18,965	24%
Block 3 Volumes		\$ 0.0175	0	0	\$ -		\$ 0.0278	\$ -	-	N/A
292 CNG/Prima Mover	0.00		12	0	\$ -	-		\$ -	-	N/A
Block 1 Volumes		\$ 0.0901	0	25,133	\$ 2,264		\$ 0.1038	\$ 2,509	\$ 244	15%
Block 2 Volumes		\$ 0.0576	0	0	\$ -		\$ 0.0713	\$ -	-	N/A
Block 3 Volumes		\$ 0.0234	0	0	\$ -		\$ 0.0371	\$ -	-	N/A
292 COGEN/CNG	25.00		24	0	\$ 600	\$ 25.00		\$ 600	-	0%
Block 1 Volumes		\$ 0.0901	0	175,397	\$ 15,303		\$ 0.1038	\$ 18,208	\$ 2,905	15%
Block 2 Volumes		\$ 0.0576	0	5,372	\$ 309		\$ 0.0713	\$ 383	\$ 74	24%
Block 3 Volumes		\$ 0.0234	0	0	\$ -		\$ 0.0371	\$ -	-	N/A
			4,230	22,551,794	\$ 2,937,442			\$ 3,287,598	\$ 550,156	19%
<u>PUBLIC AUTHORITY</u>										
211 HVAC	9.00	\$ 0.1207	0	0	\$ -	\$ 9.00	\$ 0.1838	\$ -	-	N/A
221 EXPERIMENTAL SGS	25.00	\$ 0.0995	72	677,504	\$ 69,212	\$ 25.00	\$ 0.0995	\$ 69,212	-	0%
225 PAG SR CIT SUMMER	0.00	\$ 0.1207	74	3,343	\$ 404	-	\$ 0.1838	\$ 614	\$ 211	52%
225 PAG SR CIT WINTER (weather sensitive)	0.00	\$ 0.1207	104	16,252	\$ 1,974	-	\$ 0.1838	\$ 3,005	\$ 1,032	52%
225 PAG GS - SUMMER	9.00	\$ 0.1207	2,401	108,095	\$ 34,654	\$ 10.00	\$ 0.1838	\$ 43,875	\$ 9,222	27%
225 PAG GS - WINTER (weather sensitive)	12.00	\$ 0.1207	3,370	528,703	\$ 104,256	\$ 13.00	\$ 0.1838	\$ 140,999	\$ 36,731	35%
			6,022	1,333,997	\$ 210,500			\$ 257,896	\$ 47,396	22%
<u>TRANSPORTATION</u>										
250 - TRANSP (220 SML COM/INDG)	310.00	\$ 0.1851	22	153,483	\$ 35,230	\$ 310.00	\$ 0.2422	\$ 40,394	\$ 5,164	25%
260 - TRANSP (230 LRG COM/INDG)	310.00	\$ 0.1966	379	7,965,796	\$ 1,882,566	\$ 310.00	\$ 0.2172	\$ 1,847,961	\$ 164,395	10%
260 - TRANSP (240 DEMAND/COMM GS)	310.00		13	0	\$ 4,030	\$ 310.00		\$ 4,030	-	0%
Block 1 Volumes		\$ 0.0901	0	253,230	\$ 22,916		\$ 0.1038	\$ 26,285	\$ 3,369	15%
Block 2 Volumes		\$ 0.0576	0	593,290	\$ 34,174		\$ 0.0713	\$ 42,302	\$ 8,128	24%
Block 3 Volumes		\$ 0.0234	0	0	\$ -		\$ 0.0371	\$ -	-	N/A
Demand Volumes		\$ 1.6293	0	51,635	\$ 94,129		\$ 1.6293	\$ 84,129	-	0%

Atmos Energy Corporation
Exhibit PJ-C-1

	Rates effective Dec06		Adjusted Base Count	Adjusted Volumes Ccf	Current Adjusted Margin Rev	Proposed Rates		Total Revenues	Increase	Percent Change
	Monthly Customer chg	Commodity Charge/Ccf				Monthly Customer chg	Commodity Charge/Ccf			
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)
260 - TRANSP (290/240 ECON DEV - DEMAND/C	310.00		12	0 \$	3,720 \$	310.00		3,720 \$	-	0%
Block 1 Volumes		\$ 0.0875	0	240,000 \$	16,200		\$ 0.0779	18,684 \$	2,484	15%
Block 2 Volumes		\$ 0.0432	0	410,760 \$	17,745		\$ 0.0535	21,965 \$	4,221	24%
Block 3 Volumes		\$ 0.0175	0	0 \$	-		\$ 0.0278	- \$	-	N/A
Demand Volumes		\$ 1.2220	0	35,526 \$	43,535		\$ 1.2220	43,535 \$	-	0%
280 - TRANSP (250 OPT GS MASS METER)	310.00		24	0 \$	7,440 \$	310.00		7,440 \$	-	0%
Block 1 Volumes		\$ 0.0901	0	392,170 \$	35,335		\$ 0.1038	40,707 \$	5,373	15%
Block 2 Volumes		\$ 0.0576	0	366,470 \$	21,109		\$ 0.0713	26,129 \$	5,021	24%
Block 3 Volumes		\$ 0.0234	0	0 \$	-		\$ 0.0371	- \$	-	N/A
260 - TRANSP (250 OPT GS)	310.00		541	0 \$	167,710 \$	310.00		167,710 \$	-	0%
Block 1 Volumes		\$ 0.0901	0	10,147,168 \$	914,260		\$ 0.1038	1,053,276 \$	139,016	15%
Block 2 Volumes		\$ 0.0576	0	27,993,068 \$	1,612,401		\$ 0.0713	1,995,906 \$	383,505	24%
Block 3 Volumes		\$ 0.0234	0	0 \$	-		\$ 0.0371	- \$	-	N/A
260 - TRANSP (280/250 ECON DEV - OPT GS)	310.00		28	0 \$	8,680 \$	310.00		8,680 \$	-	0%
Block 1 Volumes		\$ 0.0675	0	473,690 \$	31,974		\$ 0.0779	36,877 \$	4,903	15%
Block 2 Volumes		\$ 0.0432	0	1,657,500 \$	71,608		\$ 0.0535	88,640 \$	17,032	24%
Block 3 Volumes		\$ 0.0175	0	0 \$	-		\$ 0.0278	- \$	-	N/A
Total Transportation				50,733,987 \$	4,815,660			5,561,670 \$	1,940,713	40%
Sub Total				195,834,934 \$	44,210,624			54,753,592 \$	11,737,871	
Special Contracts					\$ -			\$ -	N/A	N/A
4870 - Forfeited Discount					\$ 1,366,914			\$ 1,433,015	\$ 66,201	
4880 - Miscellaneous Service charges					\$ 175,696			\$ 821,140	\$ 445,444	
TOTAL MARGIN REVENUES					\$ 46,345,608			\$ 57,400,221	\$ 11,054,613	24%

CAPITEX/HRIS
MPL C9

CUSTOMER UTILIZATION ADJUSTMENT (CUA) RIDER

Provisions for Adjustment

This Rider shall apply to and become part of Atmos Energy Corporation's (Company's) Rate Schedules 210, 220, 225 and 230. The base rate per Ccf for gas service set forth in the referenced Rate Schedules shall be adjusted by an amount hereinafter described, which is referred to as the "Customer Utilization Adjustment" (CUA). The CUA shall apply to all residential, commercial and public authority bills within the above referenced Rate Schedules. This CUA Rider is intended to authorize the Company to recover or refund (positively or negatively) margins associated with volume changes other than those related to weather (which are corrected through the Company's Weather Normalization Adjustment Rider).

Definitions

For purpose of this Rider:

"Regulatory Authority" means the Tennessee Regulatory Authority

"Relevant Rate Order" means the final order of the Regulatory Authority in the most recent litigated rate case of the Company fixing the rates of the Company or the most recent final order of the Regulatory Authority specifically prescribing the factors and procedures to be used in the application of this Rider.

Computation of Customer Utilization Adjustment

The CUA shall be computed to the nearest one-hundredth cent per Ccf by the following manner:

- 1) The CUA shall be calculated for each customer class in the referenced rate schedules as the difference between the test-year average margin per customer as determined in the Relevant Rate Order and the actual average margin per customer (including margins from the Weather Normalization Adjustment), multiplied by monthly average number of billing units for the CUA accounting/recovery period.
- 2) The annual CUA factor shall be obtained by dividing the total margin difference less cumulative collections as of the CUA accounting/recovery period by the number of Ccf for each class in the referenced rate schedules distributed by the Company during the CUA accounting/recovery period.

The annual CUA factor shall be recovered in addition to the commodity/volumetric charges for the Company's Rate Schedules 210, 220, 225 and 230.

Filing with the Authority

Each CUA accounting/recovery period shall correspond with the Company's Fiscal Year which ends September 30 each year.

The Company shall charge all authorized CUA margins to the "Deferred Margin" account and shall file supplemental sheets as may be required by the Authority showing the calculation of the CUA factors and activities.

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF THE APPLICATION)
OF PUBLIC SERVICE COMPANY OF NEW)
MEXICO FOR A REVISION TO ITS RATES,)
RULES, AND CHARGES PURSUANT TO)
ADVICE NOTICE NOS. 755 AND 756,)
PUBLIC SERVICE COMPANY OF NEW MEXICO,)
Petitioner.)
_____)

Case No. 06-00210-UT

RECOMMENDED DECISION OF THE HEARING EXAMINER

Lee W. Huffman, Hearing Examiner for this case, submits this Recommended Decision to the New Mexico Public Regulation Commission ("Commission" or "NMPRC") pursuant to 17.1.2.32.E(4) and 17.1.2.39.B NMAC. The Hearing Examiner recommends that the Commission adopt the following Statement of the Case, discussion, findings of fact, conclusions of law and decretal paragraphs in its Final Order. A Table of Contents has been included for convenience of reference.

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STATEMENT OF THE CASE

On May 30, 2006, Public Service Company of New Mexico ("PNM") filed its Petition for a Revision to Retail Natural Gas Rates and Rules ("Petition") with accompanying direct testimonies, schedules and work papers. The testimony filed with PNM's Petition is the testimony of: Melvin J. Christopher, Tommy H. Sanders, Ralph A. Morris, Roger Larsen, Gary W. Boyle, Laura Patterson, Matthew F. Harland, Samuel C. Hadaway, Thomas G. Sategna, David S. Gutzler, Russell A. Feingold and John M. Fernald. Also on May 30, 2006, PNM filed its Supplement to Petition for a Revision to Retail Natural Gas Rates and Rules that included Schedule R-7, Opinion of Independent Public Accountants.

PNM filed Errata to the following direct testimony supporting its Petition: David S. Gutzler on July 17, 2006; Russell A. Feingold on July 28, 2006; Ralph A. Morris, Tommy H. Sanders, John M. Fernald, Gary W. Boyle and Russell A. Feingold on August 23, 2006; Thomas G. Sategna on October 27, 2006; and Matthew F. Harland on November 8, 2006.

On June 20, 2006, the Commission entered its order suspending rates and appointed Lee W. Huffman as Hearing Examiner to preside over any hearings in this case.

On July 5, 2006, the Hearing Examiner issued an order scheduling pre-hearing conference. On July 18, 2006, the Hearing Examiner issued a procedural order that: set December 11, 2006, as the date for a public hearing; required the filing of rebuttal testimony on or before December 4, 2006; required Staff and Intervenors to file direct

testimony on or before November 13, 2006; and, required PNM to publish Notice on or before July 25, 2006.

On July 25, 2006 PNM filed an Application for a variance from the requirement in the July 18, 2006, procedural order requiring PNM to publish Notice on or before July 25, 2006. In its Application, PNM requested an extension of two days to publish Notice. PNM's Application for Variance was granted by the Hearing Examiner by an order dated October 16, 2006.

On August 3, 2006, PNM filed a Motion for Protective Order. This Motion was granted and a Protective Order issued as provided in the August 31, 2006, Order of the Hearing Examiner.

On August 4, 2006, PNM filed its Affidavit of Publication showing that the Notice required by the Hearing Examiner's July 18, 2006, Procedural Order was published on July 27, 2006, which was timely under the provisions of the Hearing Examiner's October 16, 2006, Order. On September 6, 2006, PNM filed its Affidavit of Notice to Customers. In its Affidavit, PNM states that a copy of the notice required by the Hearing Examiner's July 18, 2006, Procedural Order was inserted into customer's invoices commencing July 25, 2006.

Motions for Leave to Intervene were filed in this case by: NMIEC on June 6, 2006; the City of Farmington on June 21, 2006; the AG on June 21, 2006; Conoco Phillips Company on June 27, 2006; the ICLA on June 27, 2006; NNSA on June 29, 2006; UNM on July 7, 2006; CANM on July 13, 2006; the COA on July 17, 2006; the Albuquerque Bernalillo County Water Utility Authority ("ABCWUA") on July 27, 2006; and NRDC/SWEEP on August 17, 2006. The AG filed an Amended Motion for Leave to

Intervene on August 3, 2006, and a Second Amended Motion for Leave to Intervene on August 4, 2006. The COA filed an Amended Motion to Intervene on August 16, 2006.

Signed Confidentiality Agreements were filed in this case on: July 28, 2006, by Jeff Taylor, Loretta S. Martinez, Andrea C. Crane, Lisa Albee, Marjorie M. Levin and Steven W. Ruback; August 4, 2006, by Carolyn S. Fudge; August 10, 2006, by Lewis O. Campbell and Paul N. Jones; August 16, 2006, by David B. Nava and Robert D. Kidd, Jr.; on August 25, 2006, by Bruce Throne, John Tysseling, Jill Roelle, and Daniel Craig; on September 11, 2006, by Daniel A. Najjar; on September 14, 2006, by Jatinder Kumar; on November 16, 2006, by James A. Brack, Phillis Stevens, Andrea Delling, Dahl Harris, Steven Schwebke, Anthony R. Sisneros and Charles Gunter; on November 17, 2006, by Roger D. Colton, Jami Porter Lara and Michael J. Hely; on December 5, 2006, by Gary G. Roybal.

On November 1, 2006, the New Mexico Attorney General ("AG") filed a Motion to amend the procedural schedule by extending the date for Staff and Intervenors to file direct testimony from November 13, 2006, to November 17, 2006. This Motion was granted by the Hearing Examiner by Order dated November 6, 2006.

On November 8, 2006, PNM filed a Motion to amend the procedural schedule by extending the date for PNM to file its rebuttal testimony from December 4, 2006, to December 6, 2006 and, extend the beginning date of the public hearing from December 11, 2006, to December 13, 2006. This Motion was granted by the Hearing Examiner by Order dated November 9, 2006. On November 28, 2006, the Hearing Examiner entered an order amending his November 9, 2006 Order by specifying that any rebuttal testimony could be filed on December 6, 2006.

On November 15, 2006, the Hearing Examiner issued an Order establishing an Official Service List. This list was corrected by the Hearing Examiner by Order dated November 16, 2006.

On November 17, 2006, direct testimony was filed on behalf of: UNM by Daniel B. Craig; Natural Resources Defense Council and Southwest Energy Efficiency Project ("NRDC/SWEEP") by Sheryl Carter; NMIEC by Michael D. Dirmeier; Staff by Steven D. Schwebke, Phillis Stevens, Andrea B. Delling, Thomas C. Patin, Anthony R. Sisneros, and James A. Brack; Community Action New Mexico ("CANM") by Roger D. Colton; the AG by Andrea C. Crane, Steven W. Ruback and Gary G. Roybal; and, NNSA by Jatinder Kumar. On November 30, 2006, Staff filed Errata to the direct testimony of Andrea B. Delling.

On November 20, 2006, the United States Department of Energy and the United States National Nuclear Security Administration ("NNSA") filed a Motion requesting that it be allowed to file direct testimony on November 20, 2006, rather than on November 17, 2006. This Motion was granted by the Hearing Examiner by Order dated November 21, 2006.

On December 6, 2006, rebuttal testimony was filed on behalf of: UNM by Daniel B. Craig; NRDC/SWEEP by Sheryl Carter; the AG by Andrea C. Crane; NNSA by Jatinder Kumar; PNM by Tommy H. Sanders, Deborah J. Brunt, Gary W. Boyle, Roger Larsen, Laura Patterson, Matthew F. Harland, Samuel C. Hadaway, Gene Wickes, Thomas G. Sategna, David Gutzler, Russell A. Feingold, Ronald H. Edgington and John M. Fernald.

On December 8, 2006, the Regents of the University of New Mexico ("UNM") filed a Motion to Strike portions of the rebuttal testimony of Gene Wickes and Thomas Sategna filed by PNM on December 6, 2006, or, in the alternative, to allow Intervenors and Staff to present oral rebuttal testimony addressing the challenged rebuttal testimony and a portion of the tax treatment of prepaid pension asset in the rebuttal testimony of Matthew Harland. On December 8, 2006, the Hearing Examiner issued an e-mail Order to the parties requiring any responses to UNM's Motion to Strike to be made by 4:00 p.m. on December 11, 2006.

On December 11, 2006, the AG and the New Mexico Industrial Energy Consumers ("NMIEC") filed a Joint Motion to Strike portions of the rebuttal testimony of PNM witness Thomas G. Sategna concerning other gas supply expense on the basis it was improper rebuttal testimony. On December 11, 2006, the Hearing Examiner issued an e-mail Order to the parties requiring any responses to the Joint Motion to Strike to be made by 4:00 p.m. on December 12, 2006.

On December 12, 2006, PNM filed its Responses to UNM's Motion to Strike and to the Joint Motion to Strike filed by the AG and NMIEC. At the hearing, the Hearing Examiner denied the Joint Motion to Strike, and ruled that as to UNM's Motion to Strike, live rebuttal testimony would be allowed concerning the prepaid pension asset. Tr. 12/13/06, pp.18-19.

The public hearing of this case began on December 13, 2006 and concluded on December 20, 2006 after six days of hearing. Attorney's entering their appearance during the public hearing were:

<u>For PNM:</u>	Clyde Worthen Tom Domme Madonna Bixby Benjamin Phillips	
<u>For UNM:</u>	Bruce C. Throne	
<u>For NRDC:</u>	Aletta Belin	
<u>For the AG:</u>	Jeff Taylor	
<u>For NNSA:</u>	Paul Jones	
<u>For NMIEC:</u>	Steven Michel Peter Gould	
<u>For CANM:</u>	Clark de Schweinitz Micah Rose Michael Hely	
<u>For Staff:</u>	Dahl H. Harris	
<u>For the City of Albuquerque:</u>	David Bruce Nava	
<u>For the City of Farmington:</u>	Sunny Nixon	
<u>For the Incorporated County of Los Alamos (ICLA):</u>		Dan Najjar

Witnesses testifying at the Public Hearing were:

<u>For PNM:</u>	Melvin J. Christopher Tommy H. Sanders Deborah J. Brunt Gary W. Boyle Matthew F. Harland Roger Larson Laura Patterson Russell A. Feingold Gene Wickes Samuel C. Hadaway Thomas C. Sategna David S. Gutzler Ronald H. Edgington John M. Fernald

<u>For NRDC:</u>	Sheryl Carter
<u>For the AG:</u>	Andrea C. Crane Steven W. Ruback Gary G. Roybal
<u>For NNSA:</u>	Jatinder Kumar
<u>For UNM:</u>	Daniel B. Craig
<u>For CANM:</u>	Roger D. Colton
<u>For Staff:</u>	Steven D. Schwebke Phillis Stevens Andrea B. Delling Thomas C. Patin Anthony R. Sisneros James A. Brack

At the hearing, PNM witness Brunt adopted the direct testimony of PNM witness Ralph Morris, who filed direct testimony, but did not appear at the hearing.

Written Comments were filed in this case by Linda Terell, Nathum B. Castillo, John Montano, Carmen A. Osborne and Robin S. Baltzer. Oral comments were made at the public hearing by: Warren Salomon on behalf of AARP; Norman Budow; and Carla J. Sonntag on behalf of the New Mexico Utility Shareholder's Alliance.

Following the hearing, the Hearing Examiner issued Orders on December 28, 2006, setting a briefing schedule and terminating the party status of Conoco Phillips and ABCWUA for not participating in the hearing. Later, the parties requested extensions of time to file post-hearing briefs, which were granted. On January 25, 2007, the Commission extended the suspension period in this case to June 30, 2007.

On February 15, 2007, Briefs in Chief were filed by: Staff, the AG, PNM, NMIEC, UNM, NRDC/SWEEP, CANM and NNSA. On March 5, 2007, Reply Briefs were filed by

all of the same parties, except NMIEC. On February 20, 2007, NRDC/SWEEP filed a revised Brief in Chief, correcting minor errors. On February 21, 2007 PNM and on February 23, 2007, NNSA filed errata to their Briefs in Chief.

At the hearing, the Hearing Examiner discussed on the record, without objection, the need for Staff and PNM witnesses to provide the Hearing Examiner with revised rate design allocation, rate base, proof of revenue and cost-of-service revenue requirement calculations to reflect the decisions to be made after briefing. Tr. 12/20/06, pp.122-123. Pursuant to this arrangement, on May 2, 2007, PNM filed confidentially agreements signed by PNM witnesses Sategna, Fernald and Harland. On April 27, 2007, Staff filed the confidentiality agreement for Staff witness Brack, and on May 10, 2007, for Staff witness Delling.

In all, the record developed in this case includes over 600 pages of post-hearing briefs, over 1,000 pages (not including exhibits) of pre-filed testimony and over 1,500 transcript pages from the six-day hearing.

DISCUSSION

Introduction

The Supreme Court explained the ratemaking process in Hobbs Gas Co. v. New Mexico Public Service Commission, 94 N.M. 731, 733, 616 P.2d 116 (1980).

The traditional elements of the ratemaking process and the establishment of the total revenue requirement are (1) determination of the costs of the operation, (2) determination of the rate base which is the value of the property minus accrued depreciation, and (3) determination of the rate of return. C. Phillips, The Economics of Regulation 178 (1972). This ratemaking process involves decisions as to whether certain utility investments or expenditures should be included or excluded under the above elements.

To aid in making these decisions, a test year is used to establish a utility's actual expenses necessary to provide utility service over a known period. C. Phillips, The Economics of Regulation 182 (1984). A natural gas utility recovers its expenses such as maintenance, depreciation, salaries, taxes and gas purchases. The Supreme Court recognized that a natural gas utility is not entitled to and does not receive any profit from the operation of its Purchased Gas Adjustments Clause ("PGAC"); it is only allowed to recover its actual costs of purchasing gas. Maestas v. New Mexico Public Service Commission, 85 N.M. 571, 573, 514 P.2d 847 (1973). A utility only receives a profit on "prudent investments at their actual cost when made ... [and is] limited to a standard rate of return..." Duquesne Light Co. v. Barasch, 488 U.S. 299, 309 (1989).

Through its filing of Advice Notices 755 and 756 on May 30, 2006, PNM seeks revisions to its rates, rules and charges for its natural gas transmission and distribution services. The filing is founded on a base period ending December 31, 2005 and reflects a test period revenue requirement of \$160,252,705, which is a requested increase of \$20,069,609 over the base year cost-of-service revenues of \$140,183,096. PNM's requested rate increase includes a request for an increase of \$203,000 in miscellaneous service fees. This service fee request was not opposed. The requested revenue requirement is based on an overall rate of return of 8.72% and a 11.00% return on common equity. PNM states that its present revenue deficiency causes it to earn close to a 5.9% return on equity. PNM adjusted its position by the end of the hearing to a requested \$21,305,330 rate increase, with an adjusted revenue requirement of \$161,488,426.

Staff, the AG and NNSA developed and presented separate revenue requirement proposals. Based on a return on equity of 8.50% and an overall cost of capital of 7.43%, Staff's initial position was to recommend a revenue requirement increase of \$8,355,934 for PNM. By the conclusion of the hearing, based on PNM's identification of \$1,827,382 in Other Gas Supply Expense, Staff's final position is a recommended increase of \$10,183,316. The AG and NNSA relied on Staff's proposed return on equity and overall cost of capital figures. The AG's initial recommendation was to decrease PNM's revenue requirement by \$161,848. Based on the same adjustment concerning Other Gas Supply Expense, the AG's final position is a \$1,665,534 increase. NNSA's Errata to its Brief in Chief (p.1) states that its proposed revenue requirement decrease for PNM is \$10,802,422. The details of the parties' positions are discussed in the body of this recommended decision.

I. LEGAL STANDARDS FOR RATEMAKING

The New Mexico Public Utility Act (NMSA 1978, Section 62-3-1, *et seq.*) requires that public utility rates be just and reasonable. NMSA 1978, Section 62-8-1. "Section 62-8-1 offers no guidance to the Commission for achieving this goal, nor does it specify procedures." *Otero County Electric Cooperative, Inc. v. New Mexico Public Service Commission*, 108 N.M. 462, 464, 774 P.2d 1050 (1989). "To set a just and reasonable rate, the Commission must balance the investor's interest against the ratepayer's interest." *Behles v. New Mexico Public Service Commission*, 114 N.M. 154, 161, 836 P.2d 73 (1992). As the Supreme Court has concluded, "Neither [interest] is paramount.... we cannot focus solely on investor interests." *Mountain States Tel. & Tel.*

Co. v. New Mexico State Corporation Commission, 99 N.M. 1, 7-8, 653 P.2d 501 (1982).

The New Mexico Legislature provided the Commission with a declaration of policy concerning public utility regulation, including rates:

It is the declared policy of the state that the public interest, the interest of consumers and the interest of investors require the regulation and supervision of such public utilities to the end that reasonable and proper services shall be available at fair, just and reasonable rates, and to the end that capital and investment may be encouraged and attracted so as to provide for the construction, development and extension, without unnecessary duplication and economic waste, of proper plants and facilities for the rendition of service to the general public and to industry.

NMSA 1978, Section 62-3-1(B). The Supreme Court of New Mexico has concluded that the “the legislature has allowed the Commission great flexibility in the methods to be used in achieving those goals.” Southern Union Gas Co. v. New Mexico Public Service Commission, 84 N.M. 330, 331, 503 P.2d 310 (1972) (emphasis added). The Court “has recognized that the Commission exercises expert judgment” in utility ratemaking and “is vested with considerable discretion in determining the justness and reasonableness of utility rates.” Attorney General v. New Mexico Public Service Commission, 101 N.M. 549, 553, 685 P.2d 957 (1984). In reviewing Commission decisions, the Supreme Court “consistently defers to the expertise of the Commission in ratemaking matters.” New Mexico Industrial Energy Consumers v. New Mexico Public Service Commission, 104 N.M. 565, 570, 725 P.2d 244, (1986). If the Commission finds that a proposed rate is unjust after hearing, then the Commission shall determine the just and reasonable rates to be charged. NMSA 1978, Section 62-8-7(D).

In reaching its ultimate decision, the Commission is not tied down either by the New Mexico Public Utility Act or by case law to considering only a single factor in establishing rates. Instead, “[t]he Commission is vested with considerable discretion in determining whether a rate to be received and charged is just and reasonable.” Hobbs Gas Co. v. New Mexico Public Service Commission, 94 N.M. 731, 733 and 734, 616 P.2d 1116 (1980) (citations omitted). The Supreme Court has “consistently construed the [Public Utility Act] broadly rather than to limit the Commission to any one particular method [of ratemaking]; the touchstone is the reasonableness of the ultimate decision.” New Mexico Industrial Energy Consumers v. New Mexico Public Service Commission, 104 N.M. at 569-70, (citing Hobbs Gas Co., *supra*).

In setting rates, it is the end result reached not the method employed which is controlling. Attorney General v. New Mexico Public Service Commission, 111 N.M. 636, 642, 808 P.2d 606 (1991). The Commission is not bound by the opinions of experts so long as its decision is supported by substantial evidence. Attorney General, *supra*, 101 N.M. at 553-554. The Supreme Court has stated that a regulatory commission has “discretion on public policy issues involved with regard to apportionment” of rates, and that “determining the level of subsidies, if any, is a Commission function”. Mountain States Telephone & Telegraph Co. v. New Mexico State Corporation Commission, 90 N.M. 325, 333, 338, 563 P.2d 588, 596, 601 (1977).

New Mexico law on the duties of a utility regulatory body and the discretion of such a body in carrying out its duties parallels the vast corpus of federal law on these subjects. At least since the year 1950, when the Supreme Court of the New Mexico expressly cited with approval the standards enunciated in Federal Power Commission v.

Hope Natural Gas Co., 320 U.S. 591 (1944), those standards have governed New Mexico case law. New Mexico v. Mountain States Tel. & Tel. Co., 54 N.M. 315, 224 P.2d 155 (1950). In Hope, the Supreme Court of the United States stated:

We held in Federal Power Commission v. Natural Gas Pipeline Co., 315 U.S. 575 (1942), that the Commission was not bound to the use of any single formula or combination of formulas in determining rates.... Under the statutory standard of 'just and reasonable' it is the result reached, not the method employed, which is controlling. It is not the theory but the impact of the rate which counts. If the total effect of the rate order cannot be said to be unjust and unreasonable, judicial inquiry under the Federal Power Act is at an end. The fact that the method employed to reach the result may contain infirmities is not then important....

The ratemaking process under the Act, i.e., the fixing of 'just and reasonable' rates, involves a balancing of the investor and the consumer interests. Thus, we stated in the Natural Gas Pipeline Co. case that 'regulation does not insure that the business shall produce net revenues.' 315 U.S. p.590. But such considerations aside, the investor interest has a legitimate concern with the financial integrity of the company whose rates are being regulated. From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock.... By that standard the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.

320 U.S. at 602-603 (citations omitted).

In Matter of Rates and Charges of Mountain States Telephone Co., 99 N.M. 1, 8, 653 P.2d 501 (1982), the Court reaffirmed New Mexico's adherence to the Hope "end result" standard. "The proper type of inquiry which we make has been expressed by the

United States Supreme Court in Power Comm'n v. Hope Gas Co., 320 U.S. 591, [602]...(1944). 'It is not theory but the impact of the rate order which counts. If the total effect of the rate order cannot be said to be unjust and unreasonable, judicial inquiry ... is at an end.'" Therefore, the Commission must determine rates using an "end result" test.

Correlative to the "end result" test used by New Mexico and the federal courts in determining whether a utility regulatory commission's decision was just and reasonable is the "zone of reasonableness" test adopted by the Supreme Court of New Mexico and the federal courts after the announcement of that test in Federal Power Commission v. Natural Gas Pipeline Co., 315 U.S. 575, 585 (1942). As stated by the Supreme Court of New Mexico, "There is a zone of reasonableness between confiscation and extortion in which the Commission's jurisdiction to make rates should be confined." New Mexico v. Mountain States Tel. & Tel. Co., 54 N.M. at 338. Justice Frost later concluded that there "is a significant zone of reasonableness, then, between utility confiscation and ratepayer extortion." Behles, 114 N.M. at 161.

As explained by Judge Bazelon of the D.C. Circuit:

So long as the public interest—i.e., that of investors and consumers—is safeguarded, it seems that the Commission may formulate its own standards. But there are limits inherent in the statutory mandate that rates be 'reasonable, just, and nondiscriminatory.' Among those are the minimal requirements for protection of investors outlined in the Hope case. And from the earliest cases, the end of public utility regulation has been recognized to be protection of consumers from exorbitant rates. Thus, there is a zone of reasonableness within which rates may properly fall. It is bounded at one end by the investor interest against confiscation and at the other by the consumer interest against exorbitant rates.

Washington Gas Light Co. v. Baker, 188 F.2d 11, 15 (D.C.Cir.1950), cert. denied, 340 U.S. 952 (1951).

In this case, the Commission follows these principles to fairly balance the interests of ratepayers and investors and to set just and reasonable rates in a zone of reasonableness.

II. COST OF SERVICE

A. COST OF CAPITAL/RETURN ON EQUITY

1. Legal Principles.

The legal principles governing rate of return are well established. The return should be sufficient to assure confidence in the financial soundness of the utility, to maintain its credit and to raise the money necessary to properly discharge its public duties. Bluefield Waterworks and Improvement Co. v. Public Service Commission, 262 U.S. 679, 693 (1923). In Bluefield, 262 U.S. at 690 (emphasis supplied) the Court specifically found:

Rates which are not sufficient to yield a reasonable return on the value of the property used, at the time it is being used to render the service, are unjust, unreasonable, and confiscatory, and their enforcement deprives the public utility company of its property in violation of the Fourteenth Amendment.... What annual rate will constitute just compensation depends upon many circumstances and must be determined by the exercise of a fair and enlightened judgment, having regard to all relevant facts. **A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures.** The

return should be reasonably sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time, and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally.

The U.S. Supreme Court has reaffirmed what constitutes an appropriate rate of return. “[T]he return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks.” Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591 (1944). Thus, the Supreme Court established in Hope and Bluefield a market-oriented test for rate of return. Nevertheless, the Court has made it clear that public utility commissions may not rely solely on a determination of investor interests in setting a return on equity. Rather, setting an equity return requires a balancing of both investor and consumer interests. The Court explained:

The Court in Hope found appropriate criteria by inquiring whether ‘the return to the equity owner (is) commensurate with returns on investments in other enterprises having corresponding risks’, and whether the return was sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital. . . . These criteria . . . remain pertinent, but they scarcely exhaust the relevant considerations.

The Commission cannot confine its inquiries either to the computation of costs of service or to conjectures about prospective responses of the capital markets; it is instead obliged at each step of its regulatory process to assess the requirements of the broad public interest entrusted to its protection by Congress. Accordingly, the end-result of the Commission’s orders must be measured as much by the success with which they protect those interests as by the

effectiveness with which they 'maintain credit. . . and . . . attract capital.'

Permian Basin Area Rate Cases 390 U.S. 747, 790-791 (1968).

The New Mexico Supreme Court has approved this Commission's use of these standards and particularly the end result test of Hope. Attorney General v. New Mexico Public Service Commission, 111 N.M. 636, 808 P.2d 606 (1991); Mountain States Telephone and Telegraph Co. v. New Mexico State Corporation Commission, 99 N.M. 1, 653 P.2d 501 (1982); Hobbs Gas Company v. New Mexico Public Service Commission, 94 N.M. 731, 734, 616 P.2d 1116 (1980); Southern Union Gas Company v. New Mexico Public Service Commission, 84 N.M. 330, 333, 503 P.2d 310 (1972). Therefore, in setting a rate of return in this proceeding the Commission will give due regard to the interests of both shareholders and ratepayers.

The Commission recognizes that a fair rate of return is not susceptible to precise mathematical calculation or to any certain formula and is, instead, dependent on the exercise of informed and rational judgment. Mountain State Telephone & Telegraph Co. v. New Mexico State Corporation Commission, 99 N.M. 1, 8, 653 P.2d 501 (1982). The reasonableness of the ultimate decision of the Commission is the measure of the judgment exercised. New Mexico Industrial Energy Consumers v. New Mexico Public Service Commission, 104 N.M. 565, 725 P.2d 244 (1986). There is a zone of reasonableness within which the Commission is free to set a fair rate of return. State v. Mountain States Telephone & Telegraph Company, 54 N.M. 315, 338, 224 P.2d 155 (1950). The Commission must rely on its expert judgment in establishing a fair rate of return. New Mexico Industrial Energy Consumers, *supra*; Attorney General of New

Mexico v. New Mexico Public Service Commission, 101 N.M. 549, 686 P.2d 957 (1984).

The Commission is not bound by or limited to any one method of determining a fair rate of return for it is the “end result” rather than the methodology used that matters. Hobbs Gas Co., 94 N.M. at 733, 734; Mountain States Tel. & Tel. Co. v. New Mexico State Corporation Commission, 90 N.M 325, 338, 563 P.2d 588 (1977).

2. Introduction

Capital structure is the relationship between a company’s debt and equity. Capital structure influences the overall cost of capital, since capital is more expensive than debt. In general terms, the cost of capital for an investor-owned utility consists of two main components: return on long-term debt capital and return on equity capital. Many utilities also have preferred stock, which is usually a relatively small part of their capital structure. To obtain the cost of capital (the allowed rate of return) to be used for ratemaking purposes, the weighted average of the individual rates on long-term debt, preferred stock and common equity are used.

Two witnesses presented testimony concerning cost of capital in this proceeding. Staff economist Mr. Patin testified in favor of a 8.50 percent return on equity, while PNM’s witness, Dr. Hadaway, testified favor of an 11.0 percent return on equity. This was the only aspect of PNM’s capital structure that was disputed. While both witnesses relied on the discounted cash flow (“DCF”) model, there is more than one version, and Dr. Hadaway also relied on other approaches.

The DCF model is the traditional method relied on by this Commission to determine return on equity. It has been used by the Commission in the past for many

utilities,¹ including PNM Gas Services and its predecessor. See, Final Orders in Case Nos. 2662, 2147, 1787. The DCF methodology is used in a majority of the states and its use by this Commission has been expressly approved by the Supreme Court of New Mexico.

As the Supreme Court observed seven years ago in Zia Natural Gas Co. v. New Mexico Public Utility Commission, 2000-NMSC-011, ¶18, 128 N.M. 728, 998 P.2d 564, the “DCF formula ... predicted dividend growth over the long run, was supported by substantial evidence and gave the Commission an indication of the appropriate rate of return of equity. The parties are in agreement that the DCF model is well-entrenched in this jurisdiction, having been in use for at least fifteen years.” The Court approved the Commission’s use of the DCF model to determine a utility’s return on equity. “We hold that it is within the authority and discretion of the Commission to use the DCF formula, relying on recent economic circumstances and the data from the eight representative companies in this case.” Id. at ¶19.

The Court explained that “DCF is a market-based measure of return, meaning it assumes that the current market price of the stock incorporates all relevant information about investments in general and all information regarding the particular stock. The DCF ‘method determines the proper rate of return [on common equity] by adding to the common stock’s current yield a rate of increase investors expect to occur over time.’” Id. at ¶15 (citation omitted).

¹ PNM Electric, Case No. 2262, Rio Rancho Water Utilities, Case No. 2440, Hobbs Gas Co., Case No. 2462 (appeal dismissed with prejudice in New Mexico Supreme Court Docket No. 21,271) 1993 WL 278861, Zia Natural Gas Company, Case No. 2745.

While the DCF model uses the expected rate of divided growth as an input, it contemplates “all information regarding the particular stock” including its price, which “is reflective of all investment opportunities at the time.” *Id.* Competing investment opportunities, whether in another utility company or in a different field altogether, hold the potential for gain or loss of the principal invested. The same holds true for an investment in a regulated utility such as PNM, since utility regulation does not protect utilities from market forces.

[U]tilities are not shielded by the Constitution from the forces of competition and the uncertainties of economic life, and investors purchasing common stock are after all engaged in economic risk-taking.... The very existence of regulation carries with it the hard fact that not every rate increase will be granted, not every expenditure will be allowed.

Jersey Central Power & Light Co. v. F.E.R.C., 810 F.2d 1168, 1192-93 (D.C.Cir. 1987).

One of the risks that an investor takes when purchasing PNM or any utility stock is that the price of the stock will fall rather than rise. While the DCF method focuses on dividend growth, the model incorporates the potential for capital appreciation or loss, because “it assumes the current market price of the stock incorporates . . . all information regarding the particular stock.” Zia Natural Gas, at ¶15. The Commission’s past rulings, particularly in PNM gas and electric rate cases, acknowledge the implicit inclusion of potential capital gains in the DCF model. Case No. 2262 (PNM electric) Recommended Decision, p.85; Case No. 2147 (PNM Gas) Recommended Decision, p.41 (both of these Recommended Decisions were approved by the Commission Final Orders in those cases); accord, Re the Connecticut Light and Power Company, 229

P.U.R. 4th 380, 495 (Conn. D. P.U.C. 2003). Staff's view to the contrary in this case is incorrect.

Staff's additional concern about a regulated public utility receiving a rate of return on a par with "speculative growth stocks" (Brief in Chief, p.13) is misplaced because New Mexico follows the Bluefield standard. Mountain States Telephone & Telegraph Co. v. Corporation Commission, 99 N.M. 1, 8, 653 P.2d 501 (1982). New Mexico also follows the Hope standard, and the Supreme Court of New Mexico has confirmed that standard's continuing vitality. Attorney General v. New Mexico Public Service Commission, 111 N.M. 636, 642, 808 P.2d 606 (1991).

The formula for the DCF method or model recognizes that the investor's required return is equal to the expected dividend yield of a stock plus future growth in dividends. "It recognizes that the current stock price is equal to the discounted cash flow of future dividends and capital gains." Recommended Decision, Case No. 2440, p.88. The cost of equity is the discount rate which equates the stock price with the future cash flows. "The DCF method determines the present value of a series of expected dividend payments and capital gains by discounting these future payments in recognition of the time value of money." Recommended Decision, Case No. 2262, p.85.

Staff witness Patin set out the formula for the DCF model as follows:

$k_e = D_1/P_O + g$, where

k_e = cost of equity

D_1 = expected annual dividend

P_O = current stock price, and

g = expected dividend growth.

Staff Exhibit 4 (Patin Direct) pp.8-9. In Case No. 2440, Staff witness Brack used the same formula. Recommended Decision, Case No. 2440, p.89.

Professor Phillips, in his treatise relied on by both this Commission and the Supreme Court of New Mexico, uses the same formula in describing the DCF model. C. Phillips, *The Economics of Regulation* 376 (1988) (footnote omitted).

"The discounted cash flow model (DCF) represents an attempt to estimate the equity investors' capitalization rate. Mathematically,

$$k = d/p + g$$

where: k is the investor's capitalization or discount rate (i.e., the cost of capital);

d is the current dividend per share;

p is the current market price per share; and

g is the expected rate of growth in dividends per share."

In both formulas, the terms have the same definitions. The only difference between the formula found in his treatise and the one relied on by Staff is that Dr. Phillips does not use subscripts.

3. PNM's Return on Equity Position

Dr. Hadaway selected ten natural gas local distribution companies followed by Value Line, "a widely followed, reputable source of financial data often used by professional economists to estimate the cost of capital for utilities", with at least a triple-B bond rating. PNM Exhibit 18 (Hadaway Direct), p.3. "These rates are consistent with PNM's triple-B bond rating." *Id.* at 4. He used three versions of the DCF. "The DCF model is the most widely used regulatory cost of equity estimation method." *Id.* at 16.

He also performed “a risk premium analysis and a review of forecasted interest rates for the coming year as a check of reasonableness for my DCF results.” *Id.* at 2.

He stated (in his direct testimony signed on May 25, 2006 – Tr. 12/18/06, p.98) that interest rates “are projected to increase further during the coming year. Such higher interest rates mean PNM’s cost of capital will be higher while rates from this case are in effect.” PNM Exhibit 18 (Hadaway Direct), p.4. As a result, he considers his approach of using versions of DCF and risk premium “models as well as forecasted interest rates is more reliable than a single model....” *Id.* He recommends a return on equity (ROE) of 11.0 percent. *Id.* at 2. This cost of equity is his “estimate of the Company’s just and reasonable ROE.” *Id.* at 6.

Dr. Hadaway discussed risk premium methods, which add the additional equity risk of common stock to yields on government bonds. He concluded that these methods “provide confirmation for the DCF model”. *Id.* at 14-15. He pointed out academic criticism of the capital asset pricing model (“CAPM”) and did not use this model. *Id.* Instead, he used a combination of DCF and risk premium analysis. *Id.* at 23.

Dr. Hadaway explained that the DCF model “has a sound basis in theory, and ... the additional advantage of simplicity ... in essence its estimate of ROE is simply the sum of the expected dividend yield and the expected long-term dividend (or price) growth rate.” *Id.* at 16. He discussed (and used) two alternatives to the traditional or constant growth version of the DCF model. *Id.* at 18-20, 31-35.

He also discussed general economic conditions, including interest rate increases between June of 2004 and May of 2006, and estimates for additional increases later in

2006 and in 2007. Id. at 23-24. He observed that “[r]ising interest rates also make it more difficult to use traditional rate of return models to estimate the fair, ongoing cost of capital.” Id. at 26.

He described changes in the natural gas industry over the last two decades, including increased natural gas commodity prices. Id. at 27. He pointed out that a higher winter customer charge and a revenue decoupling mechanism proposed by PNM would stabilize PNM’s revenues. He asserted that without these mechanisms, an increase to PNM’s requested ROE would be appropriate “to account for its more risky position.” Id. at 28.

Dr. Hadaway also presented a summary of average gas utility ROEs allowed by state regulatory commissions in recent years. Id. at 30; PNM Exhibit 19 (Hadaway Rebuttal), p.3:

Authorized Gas Utility Equity Returns

	2004	2005	2006
1 st Quarter	11.10%(4)	10.65%(2)	10.63%(6)
2 nd Quarter	10.25%(2)	10.54%(5)	10.50%(2)
3 rd Quarter	10.37%(8)	10.47%(5)	9.60%(1)
4 th Quarter	<u>10.66%(6)</u>	<u>10.40%(14)</u>	
Full Year	<u>10.59%(20)</u>	<u>10.46%(26)</u>	<u>10.49%(9)</u>

The numbers in parentheses indicate the number of cases decided in each quarter or year. The single case result shown for the third quarter of 2006 was the result of a settlement.

Dr. Hadaway used three versions of the DCF model. PNM Exhibit 18 (Hadaway Direct), p.31. In the traditional or constant growth model, he estimated long-term growth using an equally weighted four-part average of (1) Value Line, (2) Zacks earnings per

share growth projections for the coming three to five years, (3) a sustainable growth (“b” times “r”) estimate based on Value Line’s projected retention rates² and earned rates of return for the next three to five years, and (4) a long-term estimate of nominal growth in GDP³ [gross domestic product]. *Id.* at 31-32.

For all three models he calculated an average dividend yield of 4.58% (PNM Exhibit SCH-5, p.2 of 5, column 3) using Value Line’s projections of dividends for the coming year and stock prices from Value Line. His resulting return on equity (ROE = dividend yield plus growth) calculation using the traditional constant growth DCF model in his Direct Testimony (filed in May, 2006) has a median of 9.9% and an average of 10.0%. *Id.* column 14.

He did not, however, use these traditional DCF results. “Because these results are well below my risk premium checks of reasonableness, they are excluded from my final DCF range.” PNM Exhibit 18 (Hadaway Direct), p.35. In his Rebuttal Testimony filed in December he recalculated, using current data, the ROE with the traditional constant growth DCF model and the average was 9.7% and the median was 9.6%. PNM Exhibit SCH-3, Rebuttal p.1 of 5. Again, he concluded this result “fails to meet my risk premium checks of reasonableness and, therefore, continues to be excluded from my recommended range.” PNM Exhibit (Hadaway Rebuttal), p.20.

His second DCF model used a nominal GDP growth rate projection based on data from 1947 through 2004. PNM Exhibit 18 (Hadaway Direct), p.34. Using this data, he arrived at an average historical nominal GDP growth rate of 6.60% and used it in all three of his versions of the DCF. In this, his second version, he relied on the 6.60%

² Retention rates reflect the percentage of earnings kept by a company rather than paid out as dividends.

³ GDP is, of course, the total value of goods and services produced by a nation’s economy in a year.

estimated GDP growth rate exclusively to project growth in the DCF formula. Using this Constant Growth DCF Model (Long-Term GDP Growth), he calculated an average ROE of 11.2%, with a median of 11.1%. PNM Exhibit SCH-5, p.1 of 5. In his Rebuttal Testimony, using this same method, he calculated an average ROE of 10.8%, and a median of 11.0%. PNM Exhibit SCH-3, Rebuttal p.1 of 5.

His third DCF model was a two-stage growth approach, using Value Line's three-to-five year dividend growth projections in the first stage and his same 6.60% projected growth in GDP in the second stage. His results were both⁴ an average and median ROE of 10.7%. PNM Exhibit 18 (Hadaway Direct), p.35.

In summary form, the results of his DCF calculations from all three models for his Direct Testimony in May and his Rebuttal Testimony in December are shown as follows:

**Public Service Company of New Mexico
Discounted Cash Flow Analysis
Summary of DCF Model Results**

	Traditional Constant Growth DCF Model	Constant Growth DCF Model Long-Term GDP Growth	Low Near-Term Growth Two-Stage Growth DCF Model	<u>Source</u>
GROUP AVERAGE	10.0%	11.2%	10.7%	Direct Testimony PNM Exhibit SCH-5, p.1
GROUP MEDIAN	9.9%	11.1%	10.7%	

⁴ A close inspection of the two DCF Tables above shows that in his Direct Testimony, Dr. Hadaway relied on the averages of his models (10.7% and 11.2%) to describe his "Reasonable DCF Range", while in his Rebuttal Testimony, his "Reasonable DCF Range" of 10.4% starts with the average for his Two-Stage Model, but rather than finishing with the (lower) average of 10.8% for the Long-Term GDP Growth, it moves diagonally to the (numerically higher) figure of 11.0%, the group median. Or this could reflect an unarticulated decision to use the widest possible range, whether the figure was a median or an average, which is possible since his Direct Testimony result of 10.7% was both the average and median.

	Traditional Constant Growth DCF Model	Constant Growth DCF Model Long-Term GDP Growth	Low Near-Term Growth Two-Stage Growth DCF Model	<u>Source</u>
GROUP AVERAGE	9.7%	10.8%	10.4%	Rebuttal Testimony PNM Exhibit SCH-3, p.1
GROUP MEDIAN	9.6%	11.0%	10.5%	

Dr. Hadaway, after excluding the traditional constant growth DCF Model results calculated in both his Direct and Rebuttal Testimony, testified as to his opinion of a reasonable range as follows:

Reasonable DCF Range

Direct (p.39)	10.7% - 11.2%
Rebuttal (p.20)	10.4% - 11.0%

The basis for Dr. Hadaway's exclusion of the traditional or constant growth DCF model results from his range of "reasonable DCF results" was his risk premium analysis. "Risk premium methods are based on the assumption that equity securities are riskier than debt and, therefore, that equity investors require a higher rate of return. This basic premise ... is widely accepted as a fundamental capital market principle." PNM Exhibit 18 (Hadaway Direct), p.20. He explained that risk premium estimates of the cost of equity are consistent with other current capital market costs. "The risk premium approach is especially useful because it is founded on current market interest rates, which are directly observable. This feature assures that risk premium estimates of the cost of equity begin with a sound basis, which is tied directly to current capital market costs." *Id.* at 21 (emphasis supplied).

His “risk premium recommendation is based on an intermediate [1980 to 2005] position that avoids some of the problems and concerns that have been expressed about both very long and very short periods of analysis with the risk premium model.” *Id.* at 22. His PNM Exhibit SCH-6 shows that he calculated a 4.14% equity risk premium and added it to a projected BBB utility bond yield of 6.75% to arrive at a 10.89% ROE. “First, I compare gas utility authorized ROEs for the period 1980 through 2005 to contemporaneous long-term utility interest rates. The differences between the average authorized ROEs and the average interest rate for each year is the indicated equity risk premium. I then add the indicated average equity risk premium to the forecasted triple-B utility bond interest rate to estimate ROE” *Id.* at 36 (footnote omitted)(emphasis supplied).

Dr. Hadaway also referred to other risk premium studies, both of which calculate higher risk premiums (4.5% and 5.13%) than his result of 4.14%. He added the projected 6.75% debt cost to these higher figures and obtained 11.88% (11.9%) and 11.25% for the ROEs. *Id.* at 37-39. Dr. Hadaway indicated there is only a limited⁵ use for these two higher figures. “Although the Ibbotson and H&M results should not be extrapolated directly as stand-alone estimates of the cost of equity for regulated utilities, their results provide a reasonable long-term perspective on capital market expectations for debt and equity rates of return.” *Id.* at 38.

⁵ Professor Phillips has identified several problems with risk premium analysis. “In light of these problems, many use the risk premium approach as a subsidiary method to test the results of other approaches.” C. Phillips, The Regulation of Public Utilities, 399 (1993) (footnote omitted).

Dr. Hadaway provided the following summary of his analysis, after excluding the lower results from the traditional constant growth DCF model. PNM Exhibit 18 (Hadaway Direct), p.39.

Summary of Cost of Equity Estimates

<u>DCF Analysis</u>	<u>Indicated Cost</u>
Constant Growth (GDP Growth)	11.1% - 11.2%
Multistage Growth Model	10.7%
Reasonable DCF Range	<u>10.7% - 11.2%</u>
<u>Risk Premium Analysis</u>	<u>Indicated Cost</u>
Utility Debt + Risk Premium	
Risk Premium (6.75% + 4.14%)	10.89%
Ibbotson Risk Premium Analysis	
Risk Premium (6.75% + 4.5%)	11.25%
Harris-Marston Risk Premium	
Risk Premium (6.75% + 5.13%)	11.88%
PNM Cost of Equity Capital	<u>11.0%</u>

In his Rebuttal Testimony signed on December 1, 2006, he updated his risk premium estimate based on his recalculated equity risk premium of 4.29% and a revised projected triple-B utility bond yield of 6.40%. PNM Exhibit SCH-4 Rebuttal, p.1. His new risk premium ROE result was 4.29% plus 6.40%, or 10.69% (rounded to 10.7%) *Id.*; PNM Exhibit 18 (Hadaway Rebuttal), p.21. "The updated results of the Ibbotson risk premium analysis and the Harris-Martson risk premium analysis indicate ROEs of 10.9 percent ... and 11.5 percent...." *Id.*

In conclusion, Dr. Hadaway repeated his initial recommendation of a return on equity of 11.0% for PNM in his December 1, 2006 Rebuttal Testimony. *Id.* In support of this recommendation, he mentioned "interest rate risk from projections of higher rates

over the coming year [2007 and] the company-specific risks and uncertainties that PNM is currently facing.” *Id.* Earlier in his Rebuttal Testimony he detailed both higher short-term interest rates since 2004 and higher long-term interest rates between June of 2005 and October of 2006. *Id.* at pp.4-5. His Rebuttal Testimony also points to certain computational and other errors in Mr. Patin’s testimony and argues that Mr. Patin’s “growth rate analysis is too narrow.” *Id.* at pp.10, 13-17.

4. Staff and Intervenor Positions

In his Direct Testimony (Staff Exhibit 4) signed and filed on November 17, 2006, Staff Utility Economist Thomas C. Patin testified in favor of an 8.50% return on equity.⁶ At the hearing on December 20, 2006, Staff introduced Staff Exhibit 4A, a set of corrected schedules TCP 2-4 to Mr. Patin’s testimony. These replacement schedules corrected certain computational and other errors in his testimony. He also made corrections at the hearing to his prefiled Direct Testimony to reflect the changes to his Schedules. The magnitude of the changes was small, and did not change his recommended return on equity of 8.50%.

The Attorney General adopted Mr. Patin’s recommended return on equity. AG Exhibit 1 (Crane Direct), p.7. NNSA’s witness did not have an opinion on the return on equity issue. Tr. 12/18/06, p.33. NNSA’s counsel, however, provided extensive briefing on the issue and supported Staff’s figure or, alternatively, an ROE between 9.0% and 10.0%. NNSA Brief in Chief, pp.81-92.

⁶ Staff supported PNM’s proposed costs of long-term debt and preferred stock, which are derived from actual embedded costs. Staff Exhibit 4 (Patin Direct), pp.2, 5.

Mr. Patin testified that he considered three valuation models: the standard or traditional DCF model, the Target Market-to-Book ("TMB") modification of the DCF model and the Capital Asset Pricing Model ("CAPM"). Staff Exhibit 4 (Patin Direct), p.5 He discussed TMB and CAPM and explained why he chose not to use them in his calculation of ROE. *Id.* at p.6-8. Dr. Hadaway, as noted earlier, also declined to use CAPM.

Mr. Patin then discussed the classic DCF model. "The DCF model is based on the premise that the price of a share of stock reflects all current and relevant information concerning the value of that share relative to all other investments available in the market at that time.... The price of a share of stock is determined by the discounted value of its future cash flows, realized in the form of dividends and capital gains, versus the value of all other investment choices." *Id.* at p.8. He used "the identical peer group employed in Dr. Hadaway's testimony...." *Id.* at p.9. He then described the steps taken to calculate the two components of ROE using the classic DCF model (*Id.* at pp.8-10) and concluded by explaining that "the cost of common equity is derived by adding the expected dividend yield to the expected dividend growth rate." *Id.* at p.10.

Mr. Patin disagreed with Dr. Hadaway's use of nominal GDP growth in his calculation of the dividend growth rate. *Id.* at p.11. Mr. Patin pointed out that "such an application is without precedent in New Mexico regulatory proceedings, nor does Dr. Hadaway offer examples of its use in other jurisdictions." *Id.*

Staff Witness Patin next calculated an expected dividend yield for the peer group of ten natural gas utilities of 4.28%. Adding this figure to the average expected dividend growth rate, Staff initially computed a cost of equity of 8.27% and 8.21%. *Id.* at pp.12-

15. At the hearing, he corrected these figures to 8.36% and 8.30%. Staff Exhibit 4A, Schedule TCP-3, pp.1-2. These corrections did not affect his recommended ROE of 8.50%.

5. Commission Analysis

In its Brief in Chief, (p.3), PNM identifies three principal reasons for the difference between its and Staff's proposed return on equity. "First, Staff does not acknowledge or compare its ROE recommendation to the returns allowed in recent years by other state regulators. Second, Staff gives no consideration to interest rates that have occurred over the past eighteen months or to the forecasted higher rates that are expected in the coming year. Third, Mr. Patin applies only one version of the [DCF] model and entirely rejects other approaches that should be considered."

Turning to the first issue, it is correct that Staff did not compare its ROE recommendation to the returns allowed in recent years in other states. NNSA's Reply Brief, (p.27) responds to this point. "If this were a rational and accurate way to set rates, then Dr. Hadaway would have recommended an ROE of 10.51%, the average of all the ROEs on PNM's Table on page 7 of its Brief in Chief. Instead, he recommended setting the ROE at 11%, higher than the ROEs set by other Commissions upon which PNM would have Mr. Patin and our Commission rely." Moreover, while Dr. Hadaway's recommended ROE of 11.0% is exactly 2.5% (or 250 basis points) higher than Mr. Patin's recommended ROE of 8.5%, PNM states in its Brief in Chief, (p.8) that the average 10.51% ROE allowed in 2004-2006 cases is "approximately 250 basis points higher than the ROE [8.50%] recommended by Staff witness Patin."

The correct difference is “about 200” basis points, or exactly 201. Because the difference between Dr. Hadaway’s recommended ROE of 11.0% and Mr. Patin’s recommendation of 8.50% is 250 basis points, the mistaken description of the difference in PNM’s Brief is easily understood.

Other state utility commissions have been presented with arguments similar to the one PNM advances in this case. In a recent electric rate case granting a return on equity of 9.55% in 2006, the New York Public Service Commission, after mentioning the 9.60% return on equity it recently granted in another case, explained its reasoning as follows:

The New York Commission has never set any allowed returns for jurisdictional utility companies on the basis of any allowed returns set by regulatory bodies elsewhere. Such allowed returns may reflect stale data, other regulatory regimes and different weighting of evidence presented in other records. In every case, the record before the Commission provides the best efforts to ascertain the applicable financial market conditions and requirements for the cost of equity capital analysis that we require.

Re New York State Electric & Gas Corp. (Case 05-E-1222), 2006 WL 3733240, p.20 (N.Y.P.S.C. 2006).

The Illinois Commerce Commission provided an equally sound analysis of a similar request in a case in which PNM witness Dr. Hadaway testified.

ComEd asserts its cost of equity should reflect the costs of equity recently approved for electric utilities in the United States. The cost of equity appropriate to ComEd, however, is specific to that utility. ComEd may not simply adopt the cost of equity set for other utilities scattered around the country, for which the facts and circumstances are not necessarily similar. Rather, pursuant to Section 9-201 of the Act, ComEd must prove that its proposed cost of equity is just and reasonable.

Re Commonwealth Edison Company, 250 P.U.R. 4th 161, 285 (Ill. C.C. 2006) (05-597).

In New Mexico, a public utility such as PNM also bears the burden of proof in every rate case. Otero County Electric Cooperative, Inc. v. New Mexico Public Service Commission, 108 N.M. 462, 774 P.2d 1050 (1989); NMSA 1978, Section 62-8-7(A) (2003) (“At any hearing involving an increase in rates or charges sought by a public utility, the burden of proof to show that the increased rate or charge is just and reasonable shall be upon the utility.”)

As the reasoning in these two cases demonstrates, a commission decides the return on equity based on the facts in the record before it. The average return allowed in other states in other cases is not controlling. At most, the decisions on this issue in other states⁷ provide a very small part of a much larger economic picture. Accordingly, while we are mindful of all the information presented in this case, our decision is not determined by the returns granted elsewhere. Of greater significance is the recent return on equity of 9.715% recommended for a water utility (New Mexico-American Water Company) in New Mexico. Recommended Decision, Case No. 06-00208-UT, p.84 (February 12, 2007).

PNM also takes exception to Mr. Patin’s exclusive reliance on the DCF model. Brief in Chief, pp.7-9. Mr. Patin agreed that he performed only a single form of the DCF analysis, rather than two, due to his mistake. PNM Brief in Chief, pp.12-13; Tr. 12/20/06, pp.172-173; PNM Reply Brief, pp.2-3. By comparison, PNM asserts that Dr. Hadaway used a “balanced multi-factor analysis”. Brief in Chief, p.13. Dr. Hadaway

⁷ Re Southwestern Gas Corporation, 247 P.U.R. 4th 243 (Ariz. C.C. 2006) (a return on equity of 9.50% was allowed, placing primary emphasis on the DCF model result.); Re Centerpoint Energy Minnesota Gas, 254 P.U.R. 4th 23 (Minn. P.U.C. 2006) (a return on equity of 9.71% was allowed based on the DCF model).

used more than one version of the DCF in combination with a risk premium analysis. Brief in Chief, pp.8-9.

The Commission has long placed its principle reliance on the DCF model. In some cases involving PNM's gas utility, the Commission has relied on only one version of the DCF model, and in other cases a witness relied on more than one DCF version. This is also true for other natural gas utilities such as Hobbs and Zia regulated by this Commission. See, Final Orders, Case Nos. 2745, 2147, 1787, 2462, and 2662.

Quite simply, the Commission does not require that a witness for Staff, PNM or any other party rely on more than one model or more than one version of a particular model. As the Commission explained 24 years ago in another PNM case, "the commission has never intended nor stated that the testimony of a rate of return witness will be ignored unless it includes more than one methodology. The Commission continues to believe that the presentation of more than one methodology on the record can assist the Commission.... The key consideration is the presentation of sufficient evidence to allow the Commission to evaluate the judgments made in arriving at the witness' opinion and test the reasonableness of those judgments." Re Gas Company of New Mexico, 56 P.U.R. 4th 601, 606 (N.M.P.S.C. 1983) (Case No. 1787).

New Mexico is part the majority of states that place primary reliance on the DCF model. In some states, including Pennsylvania, other models are not even used. Pennsylvania Public Utility Commission v. Roaring Creek Water Co., 1995 WL 908396 (Pa. P.U.C.) (risk premium method and CAPM rejected). And in Massachusetts, the Commission concluded that "that the risk premium approach overstates the amount of

company-specific risk and therefore overstates the cost of equity.” Re Boston Gas Company, 1993 WL 560277, p.128 (Mass. D.P.U.).

In the present case Dr. Hadaway used three versions of the DCF model. All three, to varying degrees, use his historical nominal GDP growth figure of 6.60%. Nominal growth, according to Dr. Hadaway is “the real growth change plus the change in inflation.” Tr. 12/18/06, p.127.

Significantly, PNM and Dr. Hadaway have not identified a single state utility commission decision accepting historical nominal GDP growth for use in a DCF model for any regulated public utility in the United States. Not one. All that they offer by way of support is a Federal Energy Regulatory Commission (“FERC”) practice concerning not a natural gas local distribution company (“LDC”) such as PNM, but gas pipelines. Dr. Hadaway testified that “The FERC and all of its gas pipeline rate cases uses GDP as one of the components in the growth rate.” Tr. 12/18/06, p.90.

In its Reply Brief, (p.4) (emphasis supplied), PNM responded to a challenge from NNSA concerning the pertinence of this FERC practice. “Curiously ... NNSA recognizes that FERC uses the nominal GDP as a growth factor in its formulation of return on equity calculations. However, NNSA, without any reasoning, argues this is so because pipelines do not have a PGAC.” Reading the referenced portion of NNSA’s brief is informative. NNSA made the following points. “First, interstate pipelines are not local distribution companies (‘LDC’) and FERC is a federal not a state regulatory agency. Second, the nature of business of both interstate pipelines and LDC’s is very different. Further, unlike LDCs, interstate pipelines have no automatic cost recovery

provisions such as a PGAC. Finally, Dr. Hadaway does not disclose whether FERC uses nominal or real GDP growth rate.” NNSA Brief in Chief, p.87.

The Commission considers each of the four points significant and cannot, in any event, agree with PNM’s characterization of NNSA’s lack of “reasoning”. The Commission accepts NNSA’s position that a FERC practice concerning a pipeline company does not apply to a state’s regulation of a natural gas utility’s rates.

The Commission’s discussion in Case No. 2147 of PNM’s rate of return witness, Dr. Moyer’s, selection of a group of “comparable” natural gas distribution companies merits consideration. “He rejected pipeline companies because they carry a different level of risk.” Recommended Decision, Case No. 2147, p.44 (emphasis supplied). This conclusion applies with equal force to PNM’s present argument concerning FERC’s regulation of gas pipelines. PNM’s present position is undercut by Dr. Moyer’s conclusion. There is no support in FERC’s use of GDP data for a gas pipeline for PNM’s argument that a state utility regulatory commission should use such data for a regulated natural gas LDC.

In its Reply Brief, (p.4) PNM also asserts that “Dr. Hadaway describes and points to authority for each and every component of his calculation.” PNM does not describe the nature of that authority. There appears to be no legal authority for his use of historic rates of nominal GDP growth over the last 50 plus years to predict future dividend growth. While PNM and Dr. Hadaway point to no state utility commission decision accepting his use of historic nominal GDP growth, there are many decisions rejecting this approach.

The Illinois Commerce Commission has considered and rejected the use of historic GDP growth to estimate the cost of common equity. In Re South Beloit Water, Gas and Electric Company, 236 P.U.R. 4th 353 (Ill. C.C. 2004), the Illinois Commission approved a 9.87% return on equity for the natural gas utility and explained its conclusion to reject the historic GDP growth approach. “The Commission shares Staff’s concerns as to whether historical [nominal GDP growth] data can reasonably be relied on to estimate a forward-looking cost of common equity. Evidence presented by Staff ... lends support to the Commission’s view that the forecasts [by analysts of earnings growth] used by Staff [in its single stage DCF model], rather than the historic data used by the Company should be used as a proxy for future expectations in this instance.” Id. at 383.

Illinois and other states have also considered and rejected Dr. Hadaway’s testimony concerning the possible use of historic nominal GDP growth to set the return on equity using a DCF model. In Re Commonwealth Edison Company, 250 P.U.R. 4th 161 (Ill.C.C. 2006), Dr. Hadaway relied on the same 6.60% historic nominal GDP growth rate over 57 years to request an 11.0% return on equity for the electric utility in the Illinois case that he now uses in PNM’s natural gas rate case. Id. at 271, 276. The Illinois Commission granted instead a 10.045% return on equity, concluding “that the ComEd proposal [for 11.0%] is excessively high due to its improper application of the GDP growth rates....” Id. at 287.

The Illinois Commission described testimony forming part of the basis for its decision: “[Staff] testified that the Company’s argument for the use of an economy-wide GDP growth rate as a proxy for the growth of the individual utility companies in Dr.

Hadaway's samples rests on the implicit assumption that investors expect the long-term growth rates for those utilities to be similar to Dr. Hadaway's estimate of the average long-term growth rate for the overall economy. However, [Staff] asserts that ComEd has provided no information to demonstrate that the companies in Dr. Hadaway's samples are average growth companies." *Id.* at 276.

Dr. Hadaway's presentation in our case suffers from the same shortcomings. He made no showing that investors expect growth for his comparable group of natural gas utilities to be the same as the overall economy, particularly if based on his 1947-2004 (57 year) nominal GDP average. PNM Exhibit 18 (Hadaway Direct), p.34. Quite simply, PNM has failed to meet its burden of proof that historic nominal GDP growth is a useful measure of expected growth for a regulated utility.

The Illinois Commission specifically rejected the position, also advanced by PNM in our case, that analysts' growth rate projections extend over too short of a term to be relied on for the long-term growth estimate in a DCF model. "The Commission finds that the use of GDP growth rates to estimate long-term growth leads to an improper and overstated estimate of the cost of capital. Furthermore, the Commission does not find merit in the Company's assertion that a five-year period fails to adequately consider long-term growth expectations. Accordingly, ComEd's use of GDP growth rates is rejected." *Id.* at 286.

In the present case, Dr. Hadaway testified that "the constant growth DCF model also requires very long-term growth estimates (technically to infinity)...." PNM Exhibit 18 (Hadaway Direct), p.16. This position was rejected by the Illinois Commission and we agree with their conclusion. In both cases there was testimony that "security

analysts' growth estimates have been shown to be more accurate predictors of future returns than growth rates derived from historical data and are the most likely growth estimates that are built into stock prices." Re Commonwealth Edison, 250 P.U.R. 4th at 284. At hearing, Dr. Hadaway pointed out that the longest security analyst forecasts go three to five years into the future. Tr. 12/18/06, p.87. He acknowledged that studies by Rosef and Kenny, and by Rosef and Brown show that analysts' forecasts are "a little better" than forecasts that simply extrapolate data. Id. at 89-90.

In a previous gas rate case for PNM, the Commission stated its "agreement with the general approach of relying on projections for growth studies. Projections have been shown to be more accurate and more commonly relied on than historical rates." Recommended Decision, NMPSC Case No. 2147, p.43. In that case, the Commission concluded that "Value Line [is] a publication that is widely relied on by industry and investors and [is] an accurate measure of long-term forecasting as GCNM's [Gas Company of New Mexico, a division of PNM] witness Moyer has stated." Id. In that case and in a more recent PNM gas rate case, Dr. Moyer testified on PNM's behalf concerning the growth rate for his DCF model, which used analyst forecasts. Recommended Decision, P.U.C. Case No. 2662, p.128. In a gas rate case for Zia, the Commission's use of Value Line projections and the implicit growth rate formula were identified as two accepted methods for estimating dividend growth. Recommended Decision, P.U.C. Case No. 2745, p.71.

The Arkansas Public Service Commission rejected Dr. Hadaway's proposal to use nominal GDP growth in Re CenterPoint Energy Arkla, 245 P.U.R. 4th 384 (Ark. P.S.C. 2005) (The Commission allowed a ROE of 9.45% for that natural gas utility,

rather than its normal midpoint of 9.65%, because of circumstances unique to that utility). The Commission concluded that “he has failed to demonstrate that industry-specific DCF investor-expected growth rates are also equal to the nominal GDP growth rate. This is a crucial distinction. For example, a mature industry may have a rich dividend yield and a small expected growth rate, while a young industry may, conversely, have a small dividend yield and a large expected growth rate.” *Id.* at 410. One year ago, the Washington Commission rejected Dr. Hadaway’s proposal to use historical nominal GDP growth rates in the DCF formula. In doing so, that Commission concluded as well that “the simple constant-growth DCF method is generally preferable to the more complex and assumption-intensive multi-stage method.” Washington Utilities and Transportation Commission v. PacifiCorp, 2006 WL 1517095, p.51 (Wash. U.T.C.).

PNM next states that “Staff gives no consideration to interest rates that have occurred over the past eighteen months or to the forecasted higher rates that are expected in the coming year.” Brief in Chief, p.7. PNM points out that the federal funds rate has been increased from 1% to 5 ¼% since mid-2004, and the prime rate charged by banks has increased from 4% to 8 ¼% over the same time. Brief in Chief, p.8. Dr. Hadaway acknowledged that long-term rates have increased much less, by “50-70 basis points [.5-.7%] above the historically low levels reached in mid-2005.” PNM Exhibit 19 (Hadaway Rebuttal), p.4. The Commission recognizes that over time the cost of equity will generally be higher when interest rates are higher and that long-term interest rates are more significant in this regard.

Dr. Hadaway testified on another significant aspect of interest rates in both his direct and rebuttal testimony. In May of 2006, in his direct testimony he stated that interest rates “are projected to increase further during the coming year. Such higher interest rates mean that PNM’s cost of capital will be higher while rates from this case are in effect. Under these market conditions, a combination of approaches using DCF and risk premium models as well as forecasted interest rates is more reliable than a single model...” PNM Exhibit 18, p.4. Later in his direct testimony, he spelled out his view of nature of the consequences for the Commission of projected higher interest rates. “The interest rate risk associated with projections for significantly higher rates over the coming year should be considered explicitly.” *Id.* at p.39.

In his rebuttal testimony signed on December 1, 2006 (Tr. 12/18/06, p.99), he discussed long-term interest rate increases of between 50-70 basis points that took place between June of 2005 and October of 2006. PNM Exhibit 19 (Hadaway Rebuttal), p.5. His Table 2 on that same page also shows long-term interest rate decreases between May of 2006 and October of 2006 ranging from 36 to 41 basis points in four categories: borrowing costs for Baa rated utilities like PNM (decrease from 6.59% to 6.23%), average utility rates (decrease from 6.39% to 6.00%), long-term treasury rates (decrease from 5.35% to 4.94%), and 10-year treasury rates (decrease from 5.11% to 4.73%). *Id.*

While interest rates increased overall between June of 2005 and October of 2006, there were decreases between the time he filed his direct testimony in May of 2006 and the time he filed his rebuttal testimony in December of 2006. Later that month at the hearing, Dr. Hadaway testified that the federal funds rate and prime rate have not

been increased since May. 12/18/06, Tr. pp.101-103. He then described projected interest rate increases for the second half of 2006 and all of 2007. Tr. 12/18/06, pp.105-107, 141, 143.

Significantly, Dr. Hadaway testified that interest rates, projected to increase in the last half of 2006, "have come down actually." Tr. 12/18/06, p.108. In short, interest rates peaked in June of 2006 and declined 40 basis points by October of 2006. *Id.* at p.143. He agreed that the earlier 2006 projections were not on the mark, and "interest rates and forecasts have come down about 40 basis points." Tr. 12/18/06, p.109. As a result, in late 2006 interest rates were still projected to increase in 2007, but starting from a lower level. *Id.*

Even if late 2006 projections turn out correct for the remaining months of 2007, interest rates may only return to the levels they were at in May of 2006 when Dr. Hadaway filed his direct testimony. Or the most recent projections could prove to be no more accurate than the projections made earlier in 2006 and relied on by Dr. Hadaway. We cannot be certain what will happen to interest rates in the remainder of 2007, but at the time of the December 2006 hearing, Dr. Hadaway testified that "interest rates have dropped by 40 basis points or so and ROEs seemed to have dropped about 20 to 30 basis points." *Id.* at 140. Despite this ROE drop, Dr. Hadaway did not lower his recommended return on equity for PNM. Dr. Hadaway testified that he used the lower November 2006 interest rate forecasts in his rebuttal testimony, but that he did not change his recommended return on equity of 11.0%. *Id.* at 132.

Dr. Hadaway explained how he used the lower 2007 forecasted interest rate projections. "That is why in my rebuttal testimony I have an updated risk premium

analysis that does use those lower forecasts. I have explicitly taken that into account.”
Id. at p.131.

His updated risk premium analysis is shown in PNM Exhibit SCH-4 Rebuttal, p.1 of 2 (attached to his rebuttal testimony) and it shows a 10.69% ROE obtained by adding the projected Triple-B utility bond yield of 6.40% to his calculated equity risk premium of 4.29%. In May, in his direct testimony he calculated a 10.89% ROE, using a projected Triple-B utility bond yield of 6.75%. PNM Exhibit SCH-6, p.1 of 2. At the December hearing he testified that the “current Triple-B rate is about 6.1 percent The rate in June was 6.34 percent, so we’re 30 basis points lower than that right now.” Id. p.143.

At the time Dr. Hadaway used a projected interest rate of 6.75%, the rate was actually 6.39% and, more importantly, about six months later during the hearing it was down to 6.1%, not anywhere near the projected level of 6.75%.

The significance of this disparity between actual and projected interest rates is twofold. First, in both his Direct (pp.35-38) and Rebuttal Testimony (p.20), he used his risk premium checks of reasonableness to exclude, as unreasonable, the results from the constant growth or traditional DCF model. Using the higher projected interest rates raised his risk premium results, helping it appear that they produced sufficiently high results to justify, in his view, discarding the DCF outcomes of an average of 10.0% in his direct case, and 9.7% in his rebuttal. PNM Exhibit SCH-5, p.1 of 5; PNM Exhibit SCH-3 Rebuttal, p.1 of 5.

Second, in its Reply Brief (p.4), PNM makes the following claim. “Dr. Hadaway describes and points to authority for each and every component of his calculation.” His risk premium calculations, as noted, appear on PNM Exhibit SCH-6, p.1 of 2 and PNM

Exhibit SCH-4 Rebuttal, p.1 of 2. While he uses projected as opposed to actual Triple-B Utility Bond yields, he and PNM identified no “authority” for this “component of his calculation.”

The only authority we have found on the question of whether it is proper to use projected versus actual utility bond yields in this situation is in a recent decision of the Washington Commission rejecting Dr. Hadaway’s suggested use of projected utility bond yields. “Finally, we find credible the arguments offered by Dr. Rothschild and Mr. Gorman that risk premium analyses that rely on utility bond yields are better calibrated to currently-known yields rather than forecasts of future yields because currently-known yields capture much of the market’s current expectation of future inflation.” Washington Utilities and Transportation Commission v. PacifiCorp, d/b/a Pacific Power & Light Company, 2006 WL 1517095 (Wash. U.T.C.), p.51. The Commission finds that the reasoning of the Washington Commission on this point is very sound.

We also note that in describing his risk premium technique in his direct testimony, Dr. Hadaway described current rather than projected interest rates. “The risk premium approach is especially useful because it is founded on current market interest rates, which are directly observable. This feature assures that risk premium estimates of the cost of equity begin with a sound basis, which is tied directly to current capital market costs.” PNM Exhibit 18 (Hadaway Direct), p.21 (emphasis supplied).

Dr. Hadaway’s actual use of higher projected interest rates in his risk premium approach is inconsistent with his own description of that approach. His use of this approach to screen out relevant DCF model results is improper and does not alter the

fact that the excluded DCF results are relevant evidence which we can consider. Accordingly, we will consider his excluded DCF model results.

Dr. Hadaway's risk premium analysis also included data generated by Ibbotson and Harrison & Marston ("H&M"). Using their calculated risk premiums, and adding the same forecasted debt cost of 6.75%, Dr. Hadaway derived indicated ROEs of 11.25% and 11.9 (11.88)%. PNM Exhibit 18 (Hadaway Direct), pp.37-39. Importantly, Dr. Hadaway provided the following disclaimer. "Although the Ibbotson and H&M results should not be extrapolated directly as stand-alone estimates of the cost of equity for regulated utilities, their results provide a reasonable long-term perspective on capital market expectations for debt and equity rates of return." *Id.* at p.38.

Despite this disclaimer, and despite Dr. Hadaway's recognition that in May his recommended range for a return on equity was 10.7 to 11.2 and at the hearing it was from about 10.5 to about 11 (Tr. 12/18/06, p.132), PNM claims in its Brief in Chief (p.14) that his "analysis ... results in a range of 10.7% to 11.88% from which Dr. Hadaway concludes that 11% is a fair, just and reasonable rate of return for equity capital."

Dr. Hadaway, by contrast, admitted that as of December 2006 when he filed his rebuttal testimony his requested return on equity of 11.0% which had been in the middle of his range in May was now at the top. Tr. 12/16/06, p.132. This was so even though he admitted that he and PNM were by then in a changed environment: "interest rates have dropped by 40 basis points or so and ROEs seemed to have dropped about 20 to 30 basis points." *Id.* at 140.

Based on the record in this case, including actual levels of interest rates at the time of the hearing, the Commission finds that it was not reasonable for Dr. Hadaway to

exclude the results of his traditional constant growth DCF model from his recommended “reasonable” return on equity range. In his Direct Testimony the average result of this excluded model was 10.0% (which we consider more significant than the median of 9.9%). PNM Exhibit 18 (Hadaway Direct), pp.35-38, SCH-5, p.2. By excluding these results, his recommended ROE range in his Direct Testimony was, 10.7% to 11.2%. *Id.* at, pp.35-38.

In its Brief in Chief p.9, (emphasis supplied), PNM described Dr. Hadaway’s approach. “Using the various DCF analysis tools, the overall results from the DCF model employed by Dr. Hadaway indicated a reasonable ROE range of 10.7% to 11.2%. PNM Exhibit 18 (Hadaway Direct), p.39. Dr. Hadaway then compared his results to risk premium studies that he conducted.”

Actually, Dr. Hadaway compared his DCF results to his risk premium checks first, and then arrived at his higher recommended ROE range of 10.7% to 11.2% only after excluding his lower 10.0% average constant growth DCF model result. PNM Exhibit 18 (Hadaway Direct), p.35. The 10.0% return on equity was part of his overall results, but excluded.

In his Rebuttal Testimony Dr. Hadaway’s recommended range was 10.4% to 11.0%, and the average of his excluded traditional constant growth DCF model was 9.7% (the less significant median was 9.6%). PNM Exhibit 19 (Hadaway Rebuttal), p.20; PNM Exhibit SCH-3 Rebuttal, p.2. The Commission considers both his direct and rebuttal testimony traditional constant growth DCF outcomes relevant evidence which should be considered.

At the hearing in December, Dr. Hadaway acknowledged that his recommended return on equity of 11.0% was now at the top of his recommended "reasonable DCF range", while it had been in the middle of his range in his Direct Testimony in May. Tr. 12/18/06, p.132. His reasonable range in his Rebuttal Testimony was 10.4% to 11.0% and his reasonable range in his Direct Testimony had been 10.7% to 11.2%. PNM Exhibit 18 (Hadaway Direct), p.39; PNM Exhibit 19 (Hadaway Rebuttal), p.20.

The complete results of Dr. Hadaway's DCF analyses are summarized in exhibits to his testimony, and are shown below.

**Public Service Company of New Mexico
Discounted Cash Flow Analysis
Summary of DCF Model Results**

	Traditional Constant Growth DCF Model	Constant Growth DCF Model Long-Term GDP Growth	Low Near-Term Growth Two-Stage Growth DCF Model	<u>Source</u>
GROUP AVERAGE	10.0%	11.2%	10.7%	May 2006 Direct Testimony PNM Exhibit SCH-5, p.1
GROUP MEDIAN	9.9%	11.1%	10.7%	

	Traditional Constant Growth DCF Model	Constant Growth DCF Model Long-Term GDP Growth	Low Near-Term Growth Two-Stage Growth DCF Model	<u>Source</u>
GROUP AVERAGE	9.7%	10.8%	10.4%	December 2006 Rebuttal Testimony PNM Exhibit SCH-3, p.1
GROUP MEDIAN	9.6%	11.0%	10.5%	

An inspection of the above Table shows that his original range of 10.7% to 11.2% generally reflected averages, although 10.7% was also a median. His reasonable range in his rebuttal is from 10.4% to 11.0%, with the lower figure being an average, while the higher figure is the median rather than the average, which is 10.8%. It would appear that the average of 10.8% is more consistent with Dr. Hadaway's statement that since he filed his Direct Testimony "ROEs seemed to have dropped about 20 to 30 basis points." Tr. 12/18/06, p.140.

In support of his requested 11.0% return on equity Dr. Hadaway relied, in both his direct and rebuttal testimony, on "the company-specific risks and uncertainties that PNM is currently facing." PNM Exhibit 18 (Hadaway Direct), p.39; PNM Exhibit 19 (Hadaway Rebuttal), p.21. At the hearing, Dr. Hadaway admitted that he had not identified business risks for PNM's gas operation that are company specific as opposed to industry wide. Tr. 12/18/06, p.120. He added that "I haven't made a separate analysis of specific PNM risk." *Id.* at p.121. And he conceded that "I have not looked at PNM specifically, but certainly they are affected by all the things that are affecting the energy business in general, and the LDC business all across the country." *Id.* at p.122. His reliance on company specific risk to support a requested return on equity of 11.0% is misplaced. His testimony in favor of 11.0% return on equity is not persuasive.

As the Supreme Court has explained, "rate regulation is a balancing of competing interests, and we cannot focus solely on investor interests. In other words, what is required is a reasonable return, not on optimal return, on equity." Mountain States Telephone & Telegraph Co. v. New Mexico State Corporation Commission, 99

N.M. 1, 8 653 P.2d 501 (1982) (emphasis supplied). An 11.0% return on equity would be an optimal return in this case.

In this case, as the Commission has done in many past cases, we rely on the constant growth DCF method. The Commission has never accepted using nominal historic GDP growth as a basis for determining the growth rate in a DCF model. Accordingly, we will not rely on Dr. Hadaway's use of nominal historic GDP growth. Consistent with this decision, we do not accept his long-term GDP growth constant growth DCF model or his two-stage growth DCF model, because of their significant reliance on nominal historic GDP growth. As other commissions have concluded, and as we agree, using such GDP growth inflates the return on equity results above a reasonable level. It could give PNM an improper optimal return of equity on 11.0% rather than a legally required fair rate of return.

PNM has not met its burden of proof in this case that its requested return on equity of 11.0% is just and reasonable. At the same time, we consider the 8.50% rate of return recommended by Staff and supported by other parties to be too low to be fair to PNM.⁸

⁸ A major consideration in determining what is a fair rate of return to a utility is that it have the opportunity, as opposed to a guarantee, to earn the type of return described in *Hope* and *Bluefield*. In this regard, the utility's financial health is an important consideration, as is what is fair to ratepayers. While the primary focus of the parties to this case was understandably on the specifics of the large number of issues in this case, the Commission takes administrative notice of the following report from PNM Resources, which indicates that they are in good financial health. "Our ongoing earnings per diluted common share increased for the fourth straight year, and we contained operating and maintenance expenditures despite rising business costs. In addition, our board of directors approved increases in the company's common stock dividend in 2005 and early 2006, providing shareholders with an indicated annual dividend rate of \$0.88 per share – an increase of 37.5 percent since 2004." PNM Resources, 2005 Sustainability Report, p.3. PNM's gas utility is an unincorporated division of the overall company, PNM Resources.

Based on the record developed in this case we conclude that PNM's use of the traditional constant growth DCF model, if properly adjusted to remove its reliance on historic nominal GDP growth as a basis for estimating growth, can provide the basis for determining a fair rate of return. The most recent economic data in this case includes rebuttal testimony and evidence from the hearing. Turning to Dr. Hadaway's Rebuttal Testimony and exhibits, particularly PNM Exhibit SCH-3 Rebuttal, p.2 of 5, we find that he calculated a group average Dividend Yield (shown in column 3) of 4.23% and a group average growth rate of 5.42% (column 13), resulting in a ROE of $4.23\% + 5.42\%$ or 9.65%, although he shows 9.7% as the group average in column 14. It is not apparent whether this minor discrepancy is the result of rounding or an error, but our finding that historic nominal growth in GDP should not be used to estimate future growth in a DCF model requires that we re-determine the average growth rate.

The present average growth rate of 5.42% at the bottom of column (13) should be recalculated after removing the 6.60% level of Dr. Hadaway's GDP growth found in column (12). The result is reached by adding the averages for the remaining three categories of BR Growth (column 9), Zacks (column 10) and Value Line (column 11), and then dividing by three. Doing so yields $4.50\% + 4.65\% + 5.67\% = 14.82\%$, and dividing by 3 gives the corrected average growth rate of 4.94%. Adding this last figure to the average dividend yield of 4.23% shown in column (3) gives the corrected return on equity of 9.17%.

This result of a 9.17% return on equity is not the end of our analysis, but rather a starting point. This Commission in a number of rate cases has relied on Value Line predictions in determining a return on equity. By adding the Value Line dividend yield of

4.23% to the Value Line growth figure of 5.67%, the highest of the three shown, the result is a 9.90% return on equity. If the 4.23% Dividend Yield is added to the BR growth rate (column 9) average of 4.50%, the result is a 8.73% ROE and adding the same 4.23% Dividend Yield to the Zacks (column 10) average growth rate of 4.65% gives a 8.88% return on equity. The overall results are shown as follows:

Value Line	$5.67 + 4.23 = 9.90\%$
Overall Average of 3	$4.94 + 4.23 = 9.17\%$
Zacks	$4.65 + 4.23 = 8.88\%$
BR	$4.50 + 4.23 = 8.73\%$

Viewing these results individually, we consider the Zacks and BR outcomes of 8.88% and 8.73% to be too low and the Value Line outcome of 9.90% to be too high, in part because it is above the 9.70% (or 9.65%) result in Dr. Hadaway's model that still included as one fourth of its input the GDP figure of 6.60%. Even so, we can continue to use all of these results in our analysis.

We next consider it useful to consider the averages of any two of the three growth estimates (Value Line, Zacks, BR). We also consider the average of each of the three and the overall average. As shown below, we then add the dividend yield of 4.23% to each such figure to obtain a ROE.

Average Return on Equity

Value Line /Zacks	$(5.67 + 4.65)/2 = 5.16 + 4.23 = 9.39\%$
Value Line/BR	$(5.67 + 4.50)/2 = 5.085 + 4.23 = 9.315\%$
Zacks/BR	$(4.65 + 4.50)/2 = 4.575 + 4.23 = 8.805\%$
Value Line /Overall Average	$(5.67 + 4.94)/2 = 5.305 + 4.23 = 9.535\%$
Zacks/Overall Average	$(4.65 + 4.94)/2 = 4.795 + 4.23 = 9.025\%$
BR/Overall Average	$(4.50/4.94)/2 = 4.72 + 4.23 = 8.95\%$

The determination of a rate of return that is just and reasonable requires the exercise of a fair judgment using as its basis the proper consideration of all relevant facts. Mountain States, 99 N.M. at 8. In this case it is our judgment that a reasonable return on equity for PNM, based on all the evidence of record, is somewhere between a floor of the Value Line/BR average of 9.315% and a ceiling of the average of the Value Line and Overall Average result, which is 9.535%. Relying on our judgment first in arriving at this range, we can also select a fair rate of return on equity from within this range. In doing so we can, but are not required to, select the midpoint, which in this case is 9.425%. Re Public Service Company of New Mexico, 73 P.U.R. 4th 617, 631 (N.M.P.S.C. 1985) (The Commission can mix and match testimony and calculations and set a reasonable return that is not a figure that any single witness recommends). Because the Value Line figure produced the highest of the three growth rates, and because we have relied on Value Line as a useful measure in the past, the Commission determines the overall return on equity should be above the midpoint of 9.425%, and should be set at 9.53%, which is very close to our ceiling of 9.535%.

6. Capital Structure, Cost of Debt and Preferred Stock and Allowed Rate of Return.

PNM Gas Services "has no actual capital structure of its own." *PNM Gas Services v. New Mexico Public Utility Commission*, 129 N.M. 1, 1 P.3d 383, 2000 NMSC-012, ¶19. Even so, there was no controversy in this case about the capital structure that should be used, including the costs of long-term debt and preferred stock.

The requested capital structure is based on an average peer group capital structure as presented by PNM witness Dr. Hadaway. PNM Exhibit 18 (Hadaway Direct), p.5. The cost of debt and preferred stock are based on PNM's actual operating costs for the twelve months ending December 31, 2005 with adjustments for additional re-pricings since that date. *Id.* at 5-6. No party objected to the proposed capital structure or the cost of debt or preferred stock, as proposed by Dr. Hadaway. PNM Exhibit 19 (Hadaway Rebuttal), p.2. PNM's overall proposal, as shown in its Brief in Chief (p.6) is set out below.

**Public Service Company of New Mexico's
Proposed Overall Cost of Capital and Capital Structure
December 31, 2005 Adjusted Test Year**

Component	Percent of Total	% Cost	Weighted Average
Long Term Debt	48.00%	6.28%	3.01%
Preferred Stock	0.20%	6.20%	0.01%
Common Equity	51.80%	11.00%	5.698%
TOTAL	100.00%		8.72%

Staff agreed to this capital structure, cost of debt and preferred stock. Staff's proposed return on equity was 8.50%, and consequently, its overall cost of capital was 7.4298%, all as shown below and found in Staff's Brief in Chief, Exhibit 3.

**Staff's Proposed Overall Cost of Capital
and Capital Structure**

Type of Capital	% of Total Capital	Cost	Weighted Cost
Long Term Debt	48.00%	6.2800%	3.0144%
Preferred Stock	0.200%	6.2000%	0.0124%
Common Equity	51.800%	8.5000%	4.4030%
Total	100.00%		
Cost of Capital			7.4298%

Allowed Rate of Return

Using the Commission's authorized return⁹ on equity in this case of 9.53% and the other information provided by the parties results in the following recommended overall cost of capital.

**Recommended Decision
Overall Cost of Capital and Capital Structure**

Component	Percent of Total	% Cost	Weighted Average
Long Term Debt	48.00%	6.28%	3.0144%
Preferred Stock	0.20%	6.20%	0.0124%
Common Equity	51.80%	9.53%	4.9365%
Total	100.00%		
Cost of Capital			7.9633%

The allowed rate of return for ratemaking purposes, also referred to as the overall rate of return, is the weighted average cost of capital. As shown above, it is 7.9633%.

⁹ Staff points out that PNM currently uses the 12.52% return on equity allowed by the Commission in 1990 in PNM's electric rate case (Case No. 2262) for accounts including AFUDC and PGAC balancing account. Staff asks that PNM "be required to change the 12.52% rate used in these calculations to the appropriate return on equity rate that results from this case." Staff Exhibit 2 (Schwebke Direct), p.9; Staff Brief in Chief, p.21. The Commission agrees and grants Staff's request. Henceforth, PNM gas and electric shall use 9.53% in all calculations for which they previously have used 12.52%. After PNM's pending electric rate case is decided, PNM electric may use the return on equity set in that case.

B. Rate Base Determination

1. Construction Work in Progress (CWIP)

CWIP is utility plant under construction or development that is not yet complete and placed into service. Once plant is serving customers its value is booked to utility plant in service as part of rate base and the utility starts taking depreciation expense on the plant.

In this case, PNM's total CWIP claim is \$17,326,084. PNM Exhibit 20 (Sategna Direct), TGS-2, p.2. Staff recommended a CWIP disallowance of \$2,558,591 for two software projects that were "not supposed to be in service until 2007, they are not considered used and useful within a reasonable period of time from the test year ending December 31, 2005." Staff Exhibit 1 (Stevens Direct), p.6. PNM notes that all but \$1,467,029 was cleared to plant and put in service before December 31, 2006. PNM Reply Brief, p.6. The AG asks that all CWIP be removed, arguing that such investments are not serving customers, are not used and useful and lead to intergenerational inequities. AG. Exhibit 1 (Crane Direct), pp.10, 12; Brief in Chief, p.25. NNSA would disallow \$6,599,308 because it relates to CWIP that was not completed within 150 days of the end of the test period. NNSA Brief in Chief, p.22.

In response, PNM points out that the remaining \$1,467,029 related to the software project questioned by Staff is scheduled to be put in service by April, 2007, which is the earliest date on which rates in this case are expected to go in effect. PNM Reply Brief, p.6. PNM points out that Commission Final Orders in its gas rate cases (Nos. 1787, 1875 and 2147) have allowed CWIP in rate base for short-term projects not associated with revenue producing projects.

PNM emphasizes that “the Commission has specifically stated a timeframe for inclusion of CWIP projects for gas utilities; that is, the projects that are in service by the time the proposed rates would go into effect.” PNM Reply Brief, p.6. PNM relies on the Commission’s Final Order in Case No. 1787, which allowed CWIP balances into rate base, because they were:

short-term in nature, generally less than six months in duration, as is normal for the gas utility industry. These short-term projects are generally undertaken for the benefit of current New Mexico ratepayers since the facilities in question are typically used and useful by the time rates based on these items go into effect.

Re Gas Company of New Mexico, 56 P.U.R. 4th 601, 610 (N.M.P.S.C. 1983).

It is apparent from the language quoted above from Case No. 1787 that there are two aspects required of CWIP projects before they qualify for inclusion in rate base. The first is that the projects will be serving ratepayers by the time the rates go into effect and the second is that the projects are “short-term in nature, generally less than six months in duration”.

Staff’s position is that a one-year period would qualify. PNM, however, apparently overlooks the short-term consideration in arguing that a project completed by April 2007, at least 15 months after the end of the test period, qualifies.

NNSA in its Brief in Chief (p.23) discussed the issue of the “timeframe after the end of the Test Period for which the CWIP can be included. This issue was never raised and litigated in any of the previous proceedings.” The issue appears to have been raised, but not decided, in Case No. 2147 where there is a discussion of the position taken in that case by USEA [United States Executive Agencies].

USEA recommended disallowances of three projects that GCNM [Gas Company of New Mexico] classified as CWIP because they were not short-term in nature. USEA Exhibit 2, p.28. Since the Commission is accepting Staff's recommendation and the projects USEA addressed may well be included therein, the Commission does not need to rule on USEA's recommendation specifically.

Recommended Decision, Case No. 2147, p.26.

The Commission has not precisely defined "short-term" projects, but has stated in Case No. 1787 that they are "generally less than six months in duration". NNSA argues that the proper timeframe should be 150 days (or 5 months), based on a written position PNM took. NNSA states that its witness,

Mr. Kumar pointed out that the Company's selected Test Period is 12 months ended December 31, 2005 and he agreed with the Company's witness Sategna's response to Interrogatory NNSA 5-17 that only the 'known and measurable' changes occurring within 150 days after the end of the Test Period should be included (Kumar Direct, NNSA Exhibit 1, pp.9-10, NNSA Exhibit 1 Schedule 3 and Dec. 18, Tr. p.20)

NNSA Brief in Chief, p.20

In its Brief in Chief and Reply Brief, PNM mentioned the 150-day period proposed by NNSA, but PNM did not respond directly to NNSA's position. PNM Reply Brief, pp.5-6. As a result, PNM has only dealt with NNSA's position indirectly by arguing in favor of allowing CWIP into rate base for projects that will be completed before new rates go into effect, some 15 months after the end of the Test Period. PNM did not attempt to refute NNSA's 150 day position, and, more importantly, failed to deal with the point made by the Commission in Case No. 1787 that gas utility "CWIP is short-term in

nature, generally less than six months in duration....” 56 P.U.R. 4th at 610 (emphasis supplied).

NNSA also argues that going more than 150 days beyond the end of the Test Period could create a mismatch and result in piecemeal ratemaking, and concludes that test period data cannot be updated continuously with the result that rates are based on a moving target. NNSA Brief in Chief, p.20. NNSA also disagrees with Staff’s position of placing in rate base CWIP completed anytime in 2006, up to a year after the end of the test period. “The longer after the end of the test period adjustments are allowed to be made the more the resulting revenue requirements become unrepresentative of the test year. Out of test year adjustments, that increase revenue requirements, do not take account of other adjustments that may lower revenue requirements.” *Id.* at p.21.

NNSA provides another example of PNM relying on a 150-day limit for out of test period adjustments. Mr. Kumar used data through September 2006 (9 months rather than 5 months after the end of the test period) for his adjustment to Workman’s Compensation Insurance, to which PNM objected. PNM Exhibit 21 (Sategna Rebuttal), p.14. NNSA states that “Mr. Kumar corrected his mistake and used the data only until May, 2006 (Dec. 18, Tr. p.12), which is about 150 [151] days after the end of the Test Period.” NNSA Brief in Chief, p.22. NNSA also points out that PNM “contends that all of its CWIP would be completed before the rates resulting from this rate case go into effect. However, the completion of the CWIP is not the only thing which would happen after the Test Period but before the rates go into effect; new investment and expenses would be incurred and new customers would be added.” *Id.*

The Commission agrees with NNSA's position on this issue. In Case No. 1787, the Commission pointed out that "CWIP is short-term in nature, generally less than six months in duration, as is normal for the gas utility industry." 56 P.U.R. 4th at 610. In that case, the Commission determined that it is reasonable to limit CWIP for natural gas utilities to projects completed within a period that is "short-term", generally less than six months after the end of the test period. In this case, the Commission determines that the period will be for the longer of 150 days or five months. As a result, the Commission accepts NNSA's recommendation to not allow in PNM's rate base in this case CWIP in the amount of \$6,599,308 and, as a result, \$10,726,776 (\$17,326,084 - \$6,599,308) of CWIP is allowed in rate base.

2. Pre-Paid Pension Asset (PPA)

In this case PNM seeks to include in rate base a prepaid pension asset ("PPA") never previously approved by the Commission for PNM or any other New Mexico utility. This asset would be in addition to the pension expense, determined by independent actuaries, that PNM already recovers as an Operations and Maintenance ("O&M") expense in its cost-of-service.

PNM employees who went to work for the company before 1998 have a defined benefit pension plan. "As a defined benefit pension plan, the promised pensions are a commitment of PNM." PNM Exhibit 17 (Wickes Rebuttal), p.2. Since 1987, with the issuance of Statement of Financial Accounting Standard 87 ("FAS 87" or "SFAS 87"), the Commission has recognized this accrual method as the proper way to determine the pension expense a utility can recover as one of its operating costs. According to Staff witness Delling, each year PNM's

pension expense is determined by a third-party actuary and is based on a number of assumptions that eventually reflects the Company's long-term pension liability. In this rate case, PNM used SFAS 87 to calculate an annual accrual of pension expense based on future liability that reflects the near-term benefit to ratepayers. Staff agrees that PNMGS properly calculated and included the pension expense totaling \$8,341,254 as a recoverable cost in O&M expense. In addition to the pension expense, PNM is seeking to recover a portion of the prepaid pension asset in the rate base. PNM's claim of the prepaid pension asset in the current rate case contains discretionary contributions made by PNM management to cover future pension liability. In this case, PNM is requesting cost recovery of the difference between the prepaid asset funded by the PNM and the amounts collected from ratepayers. This approach seeks to recover the future liability of pension expense in PNM's proposed rate base.

Staff Exhibit 3 (Delling Direct), pp.23-24 (footnotes omitted).

PNM's witness explained that "SFAS sets forth the rules that companies must follow in determining their pension costs in order to have their accounting be acceptable under Generally Accepted Accounting Principles (GAAP) SFAS does not direct PNM how to fund the plan." PNM Exhibit 17 (Wickes Rebuttal), p.3. PNM witness Wickes agreed that pension payments are PNM's obligation. Tr. 12/15/06, p.158. And once the money is in the pension plan trust, PNM cannot take it out. Tr. 12/18/06, p.264.

The Internal Revenue Code and ERISA require a minimum annual contribution and set a maximum contribution that is tax deductible. PNM Exhibit 3 (Wickes Rebuttal), p.3. "Over the long run, the cumulative employer contributions made to a plan and the cumulative accounting costs should be equal. But, in the short run, there can be significant differences." *Id.* Mr. Wickes explained that "SFAS 87 provides a

methodology for computing pension cost based on accrual accounting and is intended to provide an orderly recognition of a company's benefit obligation over the employee's working lifetime." *Id.* at p.4. UNM witness Craig agreed that "over the life of the pension fund, the Company's SFAS 87 pension expense (i.e., the annual expense determined in accordance with SFAS 87) should match the Company's pension funding requirements." UNM Exhibit 1 (Craig Direct), p.8.

In addition to UNM, witnesses for Staff, the AG and NNSA testified against PNM's request to include its prepaid pension asset in rate base. PNM revised the amount of its PPA claim twice before the hearing. In its initial May, 2006 filing the requested amount was \$10,902,667. PNM Exhibit 20 (Sategna Direct), p.11. PNM increased this amount to \$18,968,580 in an errata filed five months later on October 25, 2006. In December, a week before the hearing, PNM reduced this amount to \$17,573,739. PNM Exhibit 21 (Sategna Rebuttal), TGS-3, p.1.

PNM stated that its prepaid pension asset "represents the gas utility's share of the difference between the amounts funded and the amount that has been included as expense in the gas operations rates since FAS 87 was enacted." PNM Brief in Chief, p.18. Determining that difference is not a simple matter. The other parties point out that in doing so, PNM relies on estimates, and must go back to 1987 when FAS 87 was adopted. Tr. 12/15/06, p.103. As the applicant, PNM bears the burden of proof on its request and its request raises several issues, including whether PNM can prove the amount of its claimed PPA, the source of the funds for its PPA, and whether its PPA is even legally eligible for rate base treatment. The parties raise additional issues, including retroactive ratemaking.

Each of these issues forms part of a larger overall question. That question is whether, in addition to the \$8.3 million in pension expense determined by actuaries (that no party opposes for cost-of-service recognition) and that is consistent with past Commission approvals, should PNM be allowed in this case to place its PPA in rate base.

As a preliminary matter, PNM acknowledges that it has never requested Commission approval of treatment of its PPA as a regulatory asset. Tr. 12/18/06, pp.264-265. NNSA witness Kumar made the same point. NNSA Exhibit 1, (Kumar Direct), p.27. As a result, the Commission has not issued an order determining that PNM can treat any contributions that exceed its FAS-87 determined pension expense, outside of a rate case test year, as a regulatory asset. Tr. 12/18/06, pp.67-70. Accordingly, PNM seeks to change a past Commission practice, one that has applied to other New Mexico utilities as well, of allowing the utility to recover its pension expense only through costs determined on an accrual basis, as permitted and determined under FAS 87.

The parties point out that PNM's PPA was funded by voluntary contributions, at levels not required by FAS 87. These facts trigger an inquiry into a basic legal principle concerning pensions. That principle is that to be allowed as an operating expense, the level of a utility's funding of a pension plan has to be required. 1 Priest, Principles of Public Utility Regulation, (1969), p.109. It appears that PNM does not meet this requirement. Even so, the Commission now considers the amount of PNM's requested PPA.

UNM described the situation as follows: "the PPA amount claimed by PNM is based on its unverifiable calculation of the difference between all of its contributions to its pension fund since it adopted SFAS 87 accounting in 1987 and the Company's unsubstantiated 'estimates' of pension expense previously 'included in' its gas service rates since that time" UNM Brief in Chief, p.19. PNM witness Wickes testified that he did not calculate the amounts on PNM Exhibit 21 (Sategna Rebuttal) TGS-3, showing what PNM represented to the Commission was recovered in rates. Tr. 12/15/06, pp.129-131. And PNM witness Sategna confirmed that the amounts shown in his rebuttal exhibit (TGS-3) used to calculate the PPA were only estimates.

Q. Right. Those are estimates, sir?

A. They are estimates in terms of we went back and identified test period amounts that we believe were included in settlements, but they are estimates, I don't disagree with that.

Q. And you simply backed those numbers out of cases, but those numbers were never identified in those cases as pension expense in current rates; correct?

A. Probably not, because a lot of those cases were stipulated. There could have been some that were litigated, but no, for the most part you are exactly correct.

Q. And in fact, asked during discovery whether or not you had any work papers showing the basis for the calculation of those numbers, your answer was no, we don't?

A. No, they are basically, I think if you look at my exhibit

Q. The question was we asked the company in discovery whether or not there were any work papers that the company could provide to show the basis for the calculation of those expense and rates figures shown on column A on the top half of UNM Exhibit 3, and your answer was no. You

answered that interrogatory and you indicated that, no, there are no work papers that show those calculations?

A. I would agree with that. However, as I was going to state, we did describe how those numbers were calculated in PNM Exhibit TGS-3, page 2 of 2, and page 1 of 2. So we attempted to explain how those calculations were done.

Tr. 12/18/06, pp.228-230.

In short, PNM witness Sategna confirmed that the figures PNM relied on to calculate the amount of the PPA included estimates and there were no work papers showing the calculations. Quite simply, the pension amounts included in rates cannot be determined in cases that were settled. UNM Exhibit 1 (Craig Direct), p.13.

UNM argued that "since PNM has not and cannot prove the accuracy of its claimed amounts of pension expense included in rates over the past 20 years and the Commission cannot verify those amounts, the amount of the PPA claimed by PNM is purely hypothetical, not reliable for ratemaking purposes and should not be approved by the Commission in this case." UNM Brief in Chief, p.23. The Commission agrees with UNM's conclusions.

A basic problem with PNM's claim in this rate case for a PPA of \$17,573,739 is that the amount cannot be verified because it includes estimates rather than being based only on actual data. PNM's requested recovery in rate base of a PPA calculated using estimates "is inconsistent with the Commission's practice of reviewing rate filings on the basis of the most recent actual data available." *Re Gas Company of New Mexico*, 24 P.U.R. 4th 635, 637 (N.M.P.S.C. 1978) (Case No. 1429) (emphasis in original). There are other problems with PNM's PPA claim which the Commission now considers.

There is also disagreement between PNM and other parties about the source of the funds¹⁰ creating the PPA. PNM witness Wickes testified that contributions to the pension trust fund, creating the PPA, were from shareholders rather than ratepayers. PNM Exhibit 7 (Wickes Rebuttal), pp.8-11; Tr. 12/15/06, pp.134-135.

NNSA witness Kumar reached a different conclusion. "Had the money come from shareholders, it would have been booked as Prepayment in Account 165 but the Company booked these amounts as Deferred Debit in Account 186 (Kumar Direct, NNSA Exhibit 1, p.26...). As Mr. Kumar explained, to his knowledge, Deferred Debits are only included if the Company has received the Commission's authority to designate the Pre-Paid Pension as a regulatory asset" NNSA Brief in Chief, p.26.

Staff witness Delling also disagreed with PNM's position that the PPA was funded with shareholder rather than ratepayer money. "I do not agree with that, not at this point in time until I have more data." Tr. 12/20/06, p.66. The Commission agrees with Staff witness Delling's conclusion. PNM has not provided sufficient information to prove that the PPA is funded with shareholder rather than ratepayer money. PNM has not met its burden of proof on this issue.

Another problem with PNM's calculation of the PPA for this natural gas rate case identified by Staff and other parties is that the total corporate PNM Resources PPA is much larger in PNM's recently filed electric rate case. This is so even though both the

¹⁰ UNM took the following position. "The fact that the Company cannot show the Commission how much pension expense it has already recovered through its current and past gas services rates with any certainty makes it impossible for PNM or the Commission to verify the amount of the prepaid pension asset claimed for ratemaking purposes. This uncertainty also confirms PNM's inability to prove how much of its claimed 'prepaid asset' came from 'shareholder capital' (as alleged by the Company), rather than ratepayers. See, e.g., FERC Opinion No. 337-A in Docket Nos. ER 84-604-013 and ER 85-156-003, Southwestern Public Service Co., 51 FERC ¶ 61,130 at 61,369 (May 3, 1990) (ratepayers cannot be asked to pay a return on 'ratepayer contributed capital.')." UNM Reply Brief, p.11 (footnote omitted).

gas and electric rate case calculations are for year-end 2005 and both calculations are for the same company. UNM points out that PNM's calculation of the corporate-wide PPA in the electric rate case is about \$42.7 million higher than the PPA amount claimed by PNM in this case. UNM Reply Brief, p.13. Staff asks the Commission "to take administrative notice that this has in fact occurred in the recent PNM electric rate case filing. Case No. 07-00077-UT, ... Vol. VII (Sategna Direct) TGS-4, W/P AA-2, p.1 of 2." Staff Reply Brief, pp.9-10. The Commission takes administrative notice of the requested document.

The AG argues that granting PNM's request to go back almost 20 years before the 2005 test year to 1987 and recognize in rate base the PPA "when no prior commission order authorized it would constitute retroactive ratemaking." AG Brief in Chief, p.24. AG witness Crane explained their position.

The Company's claim includes differences between FAS 87 and pension plan contributions dating back to 1987. PNM has had several gas and electric rate cases during this twenty-year period. To the best of my knowledge, the NMPRC has never approved the inclusion in rate base of any difference between FAS 87 expense and amounts contributed to the pension fund. Even if the NMPRC believed that the Company's claim was appropriate conceptually, which it clearly is not, it would be retroactive ratemaking to permit PNM to include any differences between FAS 87 expense and pension fund contributions that occurred up to twenty years ago, well before the NMPRC would have granted the requested ratemaking treatment.

AG Exhibit 1 (Crane Direct), pp.23-24.

PNM is seeking to recover what it believes is the difference between its past pension plan contributions and its recovery of past expenses in rates. The Supreme

Court, however, has ruled that ratemaking is prospective in nature. “Past deficits may not be made up by excessive charges in the future nor may past profits be reduced by disallowances to future operating expense.” Mountain States Tel. & Tel. Co. v. New Mexico State Corp. Comm’n., 90 N.M. 325, 341, 563 P.2d 588 (1977) (quoted authority omitted).

The Commission agrees with the AG that PNM’s requested rate base treatment of its PPA claim would, if granted, be prohibited retroactive ratemaking. Accordingly, PNM’s request must be declined for this reason alone.

PNM argues that its voluntary contributions to its pension plan “have the effect of lowering overall rates to ratepayers.” PNM Brief in Chief, p.19. PNM asserts that its voluntary pension plan contributions should be treated the same as its losses on reacquired debt. The Commission has in past cases (NMPSC Case Nos. 1916 and 2147) approved recovery of PNM’s losses resulting from refinancing debt at an overall saving. Those losses (or costs), if lower than the savings, are recoverable under Commission precedent.

In Case No. 2662, the Commission did not follow its own precedent concerning recovery of loss on reacquired debt. As a result, the Supreme Court reversed the Commission. PNM Gas Services v. New Mexico Public Utility Commission, 129 N.M. 1, 1 P.3d 383, 2000-NMSC-012. The Court described the Commission precedent as follows. “The Commission established in Case No. 1916 that it would permit recovery for losses on reacquired debt as long as the utility demonstrated that the benefit to current and future ratepayers exceeds the cost associated with the reacquisition.” *Id.* at ¶ 13. The Court concluded that in Case No. 2662 the Commission improperly departed

from its past practice. “PNMGS reasonably relied on the Commission’s prior determinations concerning losses on reacquired debt.” *Id.* at ¶ 21.

There is no past Commission approval of a PPA for PNM to rely on in this case. Instead, PNM asks the Commission to change its past practice of relying exclusively on the accrual method of FAS to determine recoverable pension expense in rates. UNM correctly points out that PNM’s request suffers from additional shortcomings, as well. UNM Brief in Chief, pp.24-28; UNM Reply Brief, pp.14-19. PNM argues there is a benefit to ratepayers from its PPA, but PNM’s analysis is based on a flawed and impermissible use of estimates. PNM has not met its burden of justifying the inclusion of its claimed PPA in rate base. The record in this case does not support PNM’s request, which the Commission determines should be denied.

Finally, PNM witness Harland testified that the ADIT (“Accumulated Deferred Income Tax”) associated with the Company’s revised PPA claim of \$17,573,739, at the statutory tax rate of 39.59%, would be \$6,957,443. PNM Exhibit 12 (Harland Rebuttal), pp.3-4. According to Mr. Harland, this adjustment is included on PNM Exhibit 21 (Sategna Rebuttal), Ex. TGS-2 Rebuttal, p.1. *Id.* at p.4. Mr. Harland testified that “ADIT is included in rate base to account for the tax benefit received from accelerated depreciation and amortization expense for tax purposes, and that the removal of an underlying project from rate base requires” the removal of ADIT associated with that project. *Id.* at p.3. PNM asks that, if the Commission rejects its requested rate base treatment of its claimed PPA, the Commission also remove the ADIT associated with that item from PNM’s proposed Test Year ADIT balance. PNM’s request concerning ADIT is reasonable and the Commission grants this request.

3. Cash Working Capital (CWC)

Cash working capital is the amount of investment needed to bridge the gap between the time expenditures are required to provide service for utility customers and the time collections are received by the utilities for those services. The Commission has explained that the

purpose of cash working capital is to provide the amount of cash needed as a result of the difference between (1) the time services are rendered until the revenues for that service are received (the lag), and (2) the time that labor, materials, fuel, etc., used in providing the service are received until they are paid for, (the lead).

Recommended Decision, Case No. 2262, p.56.

Cash working capital reflects the need for investor funds to meet day-to-day expenses of operations that arise from timing differences between when PNM must pay expenses and when customer payments are received. The purpose of a lead/lag study is to match cash outflows, or expenses, with cash inflows, or revenues. PNM performed a lead/lag study.

In this case, PNM requested inclusion of \$5,569,273 of CWC in its rate base. PNM Brief in Chief, p.21; NNSA Brief in Chief, p.39. The AG and NNSA argue for certain reductions. The AG's proposed reductions are found in two exhibits, ACC-11 (Update), and ACC-29 (Update), both attached to the AG's Brief in Chief.

The AG and NNSA argue that the lag associated with PNM's PGAC should be excluded. NNSA contends that PNM did not include the purchased gas cost in transportation service "or non-gas cost revenue requirement, and therefore, it is not proper to include any lag associated with this cost in the non-gas cost revenue

requirement....” NNSA Brief in Chief, p.39. The AG argues that “PNM already applies a carrying cost to its PGAC balancing account... [and] has not demonstrated that there is any cash working capital requirement associated with these costs.” AG Brief in Chief, pp.26-27.

In its Brief in Chief (pp.22-23) PNM explains that its CWC claim “relates to the timing of the payment of gas costs to suppliers and receiving payment from the customer for those costs.” PNM has an expense lag of 36.5 days and a revenue lag of 39.2 days. The 2.7 day difference is the basis for PNM’s CWC request. The Commission agrees with PNM that this request is proper.

Next, the AG and NNSA ask the Commission to include the lag on PNM’s payment of interest expense on long-term debt. PNM points out that this request is inconsistent with the Commission’s Final Order in Case No. 2262. PNM Brief in Chief, p.24. A review of that case shows that the Commission has already concluded it will exclude PNM’s long-term debt interest payments from the CWC computation. Recommended Decision, Case No. 2262, pp.58-59.

The AG argues that CWC associated with non-cash items such as bad debt, depreciation, amortization and deferred taxes should be excluded. AG Brief in Chief, p.27. PNM responds that it has already done so and that a zero in certain exhibit columns shows this, not that payments were made daily, as the AG assumes. PNM Brief in Chief, p.23. The Commission also determined in Case No. 2262 that non-cash items should not be included in CWC. Recommended Decision, Case No. 2262, pp.57, 59.

Finally, NNSA states that Staff should have reduced CWC to “reflect the reduction the Staff has proposed in the Company’s O&M expenses.” NNSA Reply Brief, p.9. The Commission concludes that PNM should, as necessary, recalculate its CWC to reflect the O&M approved in this case. PNM’s requested level of CWC is approved, consistent with the above requirement.

4. Depreciation and Depreciation Reserve

PNM uses depreciation rates in this case derived from the five-year study it filed with the Commission on August 31, 2006. The study was required by Commission rule. NMAC 17.3.340.10C(2). PNM made two adjustments to its depreciation amounts. PNM increased depreciation expense by \$1,229,463, reflecting the annualization of depreciation expense from the study. PNM also increased the depreciation expense by \$454,913 to reflect the annualization adjustment involving the amortization of software additions. PNM Exhibit 20 (Sategna Direct), p.23; PNM Brief in Chief, p.24. PNM states¹¹ that as “in past cases, PNM made no adjustments to its depreciation reserve relating to increases in depreciation expense.” PNM Brief in Chief, p.24.

Staff proposes to reduce PNM’s proposed total increase to rate base of \$1,684,376 by half, or \$842,188, based on a half-year convention, which assumes plant is added at mid-year. Staff Exhibit 1 (Stevens Direct), p.4. Staff, as does NNSA, disagrees with PNM’s decision to not make any adjustment to the depreciation reserve for the test period depreciation expense adjustment.

¹¹ The only other party to brief this issue, NNSA, did not dispute PNM’s statement about past cases. The cases in question were not identified by PNM or any other party.

NNSA asks the Commission to reduce PNM's rate base by the full amount of the depreciation expense of \$1,684,376. NNSA Brief in Chief, p.34. NNSA criticizes Staff's half-year approach. NNSA argues that to be consistent, because PNM uses Plant in Service and Depreciation Expense at the year-end level, then the "year-end Accumulated Depreciation must also be used." NNSA Reply Brief, p.9.

PNM relies on Mr. Sategna's rebuttal testimony to explain why both Staff and NNSA's positions are, in PNM's opinion, wrong. PNM Brief in Chief, pp.25-26. PNM's basic point is that in the test year, when a new item of plant first comes into service, there is not yet any accumulated depreciation expense because depreciation has not yet been taken on the new plant. The Commission agrees that it is proper to recognize the new plant as Plant in Service in the test year but to wait until the next year to book any depreciation expense for the new plant, because that recognition fairly reflects what will take place in the following and subsequent years: the new plant will be depreciated, and the depreciation expense will take place. PNM points out that otherwise, if accumulated depreciation is booked during the test year before any depreciation actually takes place, PNM will never be able to recover the full amount of its initial investment. Fairness, and the Commission, require otherwise.

5. Unamortized Rate Case Expense

The Supreme Court of New Mexico has ruled that because rate case expenses benefit both ratepayers and shareholders, and are part of the normal course of business for a utility, "rate case expenses are one aspect of a utility's operating costs and are recoverable in a general rate proceeding." *PNM Gas Services*, 129 N.M. at 24, ¶ 68. In

the present rate case, PNM asks to recover \$714,220¹² in rate case expense, amortized over the usual three years (the expected time between rate cases). PNM also asks to include its existing unamortized rate case balance of \$172,581 (from its previous rate case) as rate case expense in its rate base. This would increase rate base by \$184,529 to an average test period balance of \$357,110, assuming a three-year recovery. PNM Brief in Chief, pp.26-30. Staff does not oppose PNM's request.

The AG and NNSA ask the Commission to remove the unamortized rate case balance from rate base and normalize all rate case expenses. AG Brief in Chief, pp.28-29, AG Reply Brief, pp.13-14; NNSA Brief in Chief, pp.37-38, NNSA Reply Brief, pp.11-12. Their position is that since rate cases benefit both ratepayers and shareholders, there should be a sharing of costs and that PNM should not receive a return on its rate case expenses, but only a return of those expenses.

This argument is at odds with the Supreme Court's recognition that rate case expenses are a necessary part of providing utility service, no different than the utility's other costs. The Commission explained in Case No. 2147 (Recommended Decision, pp.60-61) that if Gas Company of New Mexico (PNM) "files a new rate case before the three-year period of amortization ends, the amount can continue to be amortized in subsequent rates.... Therefore, GCNM will recover its actual expense without the risk of over collection if the rates that result from this case are in effect for over one year.... Staff and USEA accepted [the rate case expense] ... amount, but recommended that it be amortized over a three-year period."

¹² PNM reduced this amount at hearing to \$696,542.23. (See, Section C.6, Rate Case Expense).

The Commission accepts PNM's proposal on this issue. This determination is consistent with the Commission's ruling in a 1997 rate case for Zia Natural Gas Company. "[Staff] testified that it is proper to allow the unamortized balance of rate case expense in rate base.... Staff proposed a three-year amortization which has been the Commission standard amortization period." Recommended Decision, Case No. 2745, pp.26-27. The Hearing Examiner and the Commission accepted Staff's positions in Zia's gas rate case. In this case, PNM will recover one third (\$232,181) of its 2006 rate case legal expense a year in rates based on this decision.

6. Injuries and Damages Reserve

PNM requests the inclusion of \$1,628,836 in rate base for injuries and damages reserves for workers' compensation, auto and general liability. The AG contends that because the reserve is funded by utility rates, and because PNM has use of the funds until injury and damage claims are paid, rate base should be reduced by the full amount. NNSA takes a similar position. PNM Brief in Chief, p.33.

PNM answers that although it initially agreed in response to interrogatory NNSA 2-49 that it would make the rate base reduction, it "determined that, because it cannot determine the source of funds for the reserve ... a reduction of rate base would be inappropriate in any amount." PNM Brief in Chief, p.34. PNM stated that it "agrees in theory with the concept described by AG witness Crane that if the amount of reserves were included in the rates charged to customers, a reduction of the reserve amount would be appropriate." PNM Reply Brief, p.14.

Setting aside PNM's initial concession about the rate base reduction, the issue comes down to a matter of proof or, more specifically, burden of proof. PNM states that neither side can prove the source of funds, so a rate base reduction is inappropriate.

PNM has the burden of proof on this issue, and the nature of that burden of proof was discussed by the New Mexico Supreme Court. "In a rate case ... it would be burdensome to require a utility to justify every expenditure which is the basis of the request for rate relief. Therefore, unless an expense is challenged, the Commission assumes it was reasonably incurred." PNM Gas Services, 129 N.M. at p.25, ¶ 72 (citations omitted). This principle reasonably applies to rate base matters as well as to operating costs.

The AG and NNSA have challenged PNM's position, so the Commission does not assume that PNM's position is reasonable. The burden of proof is squarely on PNM to prove that it is entitled to place the reserve in rate base. PNM admits it cannot determine the "source of the funds for the revenue...." PNM Brief in Chief, p.34. In doing so, PNM fails to meet its burden of proof. Accordingly, the Commission accepts the AG's position and will not include the \$1,628,836 reserve in rate base.

C. Cost of Operations

1. Recovery of Bad Debts

PNM makes what is, at least in New Mexico, a novel proposal. Instead of recovering bad debts through rates, PNM proposes to collect the \$1,467,331 portion of bad debt resulting from sales customers' failure to pay the gas cost portion of their bills through the PGAC. PNM Brief in Chief, p.30.

NMIEC opposes this request because “these costs are not the types of costs the PGAC was designed to recover.” NMIEC Brief in Chief, p.1. The Commission agrees with NMIEC. Bad debt costs fail to qualify for inclusion in the PGAC. They are not akin to commodity costs which do qualify, because bad debt costs lack, among others, the attributes of being volatile in nature and a large percentage of the total cost-of-service.

The AG, NNSA and Staff also oppose use of the PGAC to recover bad debt expenses. Staff and AG witnesses point out that PNM’s gas costs are paid to third party suppliers and bad debt costs are uncollectible costs, not costs of gas. AG Brief in Chief, p.35; Staff Brief in Chief, p.20. NNSA contends that these costs should only be collected from sales customers, not transportation customers, arguing that bad debt costs do not relate to transportation customers who do not participate in the PGAC. NNSA Reply Brief, pp.13-14. Finally, the AG argues that PNM includes “both reserve additions and the actual write-offs in its ratemaking claim, [which] results in a double count and should be rejected....” AG Reply Brief, pp.14-15.

The Commission rejects PNM’s proposal to recover bad debt through the PGAC. The types of costs properly recovered through a PGAC do not include bad debt. The Commission also concludes that the record does not justify accepting the AG’s and NNSA’s additional proposals.

2. Other Gas Supply Expense

PNM included \$526,586 as Other Gas Supply expense in its original filing in May, 2006. This category and amount of O&M is shown in an exhibit to PNM witness Sategna’s testimony. PNM Exhibit 20 (Sategna Direct), TGS-2, p.3, line 108. In his rebuttal testimony filed on December 6, 2006, the week before the hearing, Mr. Sategna

explained that PNM made an error in this category. "Account 813, Other Gas Supply Expenses, relates primarily to labor and labor-related O&M expenses of the gas acquisition, gas control and gas settlement functions, which are not properly recovered through the PGAC PNM discovered that it had inadvertently removed the \$1,827,382 PNM has now added this amount back to the O&M expenses, which results in an increase to PNM's revenue requirement." PNM Exhibit 21 (Sategna Rebuttal), p.7; TGS-3 Rebuttal, p.3, line 108.

As indicated earlier, Mr. Sategna's correction was the subject of a Joint Motion to Strike Rebuttal Testimony filed by the AG and NMIEC. At the hearing, the Joint Motion was denied. Tr. 12/13/06, pp.18-19. As a result, the correction was allowed, and PNM's requested revenue requirement increased by \$1,827,382. The total expense in this category increased from \$526,586 to \$2,353,968. The revenue requirement positions of other parties such as Staff and the AG were also increased.

NNSA opposes including any of this category of expense in cost-of-service for transportation customers: "these expenses relate to gas supplies and do not provide any gas transportation or delivery service (Kumar Direct), NNSA Exhibit 1, p.6 (sic) [55-56])." NNSA Brief in Chief, p.68. The Commission does not find NNSA's position persuasive and concludes NNSA has not met its burden of proof in challenging this expense.

3. Results Based Pay

PNM seeks to recover as a cost-of-service \$3,477,880 for its results based pay program. This amount is the five-year average for amounts charged to PNM's gas

operations for the period 2001 through 2005. The one-year base period amount for 2005 was \$2,368,925. PNM Brief in Chief, p.35.

Results pay, according to PNM, improves the quality, safety and reliability of utility service because employees must achieve operational workgroup goals to receive a payout. Eligible employees can earn up to 20% of the maximum possible award for reaching performance targets based on customer satisfaction, cost control, safety, reliability and efficiency and up to 80% of the maximum award for reaching corporate earnings per share targets. PNM Brief in Chief, pp.36-37.

PNM argues that results pay increases company performance, improves customer satisfaction and helps attract and retain good employees. PNM contends that the full amount should be passed through to ratepayers, pointing out that the alternative is to increase base salaries, a fixed cost, without requiring that operational goals be met as a precondition. PNM Brief in Chief, pp.37-39.

The AG recommends that 50% of the results pay program costs be disallowed because the majority of the incentives relate to achieving earnings per share goals, not customer and reliability related goals. AG Brief in Chief, p.36; AG Exhibit 1 (Crane Direct), pp.45-49. Staff witness Delling contends PNM has not met its burden of proof that the program's "corporate financial and EPS goals fully benefit ratepayers, as opposed to shareholders." Staff Exhibit 3 (Delling Direct), p.12. Staff recommends allocating 20% of program costs to ratepayers for non-financial workgroup performance targets and 80% to shareholders based on corporate financial goals and earnings per share targets. As a result, Staff recommends a decrease of \$2,782,304 in

Administrative and General Salaries. *Id.* at pp.12-13. NNSA offered several alternatives, including Staff's position.

The Commission accepts Staff's recommendation. Only the portion of results based pay related to workgroup goals benefits ratepayers. The earnings target goals involve a shareholder benefit that ratepayers should not be required to fund.

4. Stock Options

PNM asks to increase its expenses by \$815,159 to reflect additional benefit costs resulting from the adoption of SFAS 123R, which requires the recognition of expense relating to granting stock options. The requested expense relates only to costs for stock options granted to employees other than officers.

The AG opposes this request. The AG contends that FAS 123R has no cash impact on PNM and "has no impact on the actual cost of providing utility service. Therefore, there is no reason for the Commission to include these costs in its revenue determination." AG Exhibit 1 (Crane Direct), p.51. The AG argues that the FAS change "relates to a timing difference as to when these options are recorded by the company.... The ratemaking treatment of stock options, or of any expense, can differ from financial reporting requirements." AG Reply Brief, pp.16-17.

PNM's position is that the cost of the stock option program affects the actual cost of providing utility service and is a cash expense for PNM. Further, SFAS 123R requires the recognition of compensation expense relating to granting stock options. PNM pays the employee the difference between the option grant price and the market price at the time of exercise by the employee. This difference is recorded as an

expense for base pay compensation. PNM Exhibit 21 (Sategna Rebuttal), pp.31-33; PNM Brief in Chief, pp.40-41.

The Commission concludes that PNM has met its burden of proof on this issue and the AG's request is denied. PNM can increase its expenses accordingly.

5. Salaries Capitalized

PNM did not make an adjustment to cost-of-service for salaries capitalized in this case. NNSA suggests an adjustment relating to capitalized salaries. Based on PNM's response to interrogatory AG 1-65, NNSA witness Kumar concludes that capitalized salaries decreased in 2005. He proposes an adjustment to PNM's revenue requirement of \$1,544,361 to normalize wages capitalized. NNSA Exhibit 1 (Kumar Direct), pp.39-42.

PNM contends that because the amount of capitalized salaries did not decrease in 2005, the adjustment proposed by Mr. Kumar should not be made. PNM Exhibit 21 (Sategna Rebuttal), pp.34-36. Contrary to Mr. Kumar's conclusion, PNM argues its response to AG 1-65 only gave the appearance that salaries capitalized by PNM have decreased in 2005, but they did not. *Id.* at p.35.

In 2005, PNM changed how engineering and supervision labor were charged to capital projects. Prior to 2005, individual employees charged engineering and supervision labor costs directly to capital projects. These labor costs accumulated in the capital project accounts, maintaining the "labor" distinction. Starting in 2005, individual employees charged engineering and supervision labor costs to an engineering and supervision clearing account, and the accumulated costs were then allocated among capital projects. *Id.* This change in 2005 caused the engineering and

supervision labor charges to lose their “labor” distinction in the capital accounts and PNM did not include the engineering and supervision capitalized labor costs when calculating the percentage of direct gas services salaries capitalized in response to AG 1-65. PNM explains that the original calculation included total capitalized salaries of \$6,660,185 divided by a total salary amount of \$27,375,748, which resulted in a 24% capitalization rate. *Id.* at pp.35-36. When the engineering and supervision capitalized labor costs are included in the 2005 calculation, the total capitalized salaries increase to \$7,841,544. This number dividend by the total salary amount of \$27,375,748 results in a capitalization rate of 29%. *Id.* at p.36. PNM concludes that when the appropriate comparable data is included in the calculation, the amount of capitalized labor costs are consistent between the periods and Mr. Kumar’s proposed adjustment based on these calculation should be rejected. *Id.*; PNM Brief in Chief, pp.42-43.

The Commission accepts PNM’s position on this issue. NNSA’s request is denied.

6. Rate Case Expense

PNM’s projected rate case expense in this case was updated at hearing and the total is \$899,701.78. This amount includes \$696,542.23 for outside counsel and \$203,159.55 for in-house counsel. PNM Brief in Chief, p.43.

The AG does not oppose the amount of PNM’s claim for outside counsel. Tr. 12/15/06, p.201. The AG did not have any reason to suggest that the amount for outside counsel was not reasonable. *Id.* at p.214. The AG challenged the initial projection of \$348,816 for in-house counsel as excessive and duplicative. AG Exhibit 1 (Crane Direct), pp.55-56.

PNM points out that Commission Rule 630 (17.10.630.13H(1)(a) NMAC) and NMSA 1978, Section 62-13-3(C) (2004) require it to identify its litigation expenses, including those for in-house counsel, in support of a rate change request. PNM Brief in Chief, p.46. PNM emphasizes that, as in past cases, its “request for recovery does not include in-house legal expenses....” *Id.* Accordingly, the AG’s request to reduce PNM’s requested rate case expenses by \$348,816 is denied and PNM is granted its requested expense of \$696,542.

7. Outside Services

PNM claims a total of \$5,066,987 for outside services. NNSA does not question the level of this expense, but because this category of expense increased 61.88% from 2004 to 2005, NNSA believes there is a “need for normalizing Test Period expense” NNSA Exhibit 1 (Kumar Direct), p.52. Using a three-year average for outside services, NNSA proposes a \$1,194,812 reduction. *Id.* at 52-53.

PNM responds that normalization “is appropriate in some instances to better match the expected expenses that will be incurred while the new rates are in effect.” PNM Brief in Chief, p.48. PNM then discusses certain computational errors by Mr. Kumar and concludes that if he had “used the [correct] three-year average rather than the base period amount, his adjustment would have been an increase to Outside Service Expense of \$809,965 rather than a decrease.” *Id.*

PNM next discusses two categories of its expenses with a combined decrease of over \$3.5 million between 2004 and 2005, noting that Mr. Kumar did not propose normalizing (to PNM’s benefit) these categories. Finally, PNM notes that between 2004 and 2005 its total Administrative & General expenses increase by less than one

percent. PNM Brief in Chief, p.49. The Commission concludes that NNSA's proposed reduction should not be made, and PNM's request should be granted.

8. Customer Records and Collection Expense

PNM requests recovery of \$10,940,228 for Customer Records and Collection Expense for the test period ending December 31, 2005. PNM states that it did not include some of these expenses in a discovery response. PNM Brief in Chief, p.50

Staff recommends that the Commission approve a three-year average from 2003 through 2005 as the appropriate number to be included in O&M expenses for Customer Records and Collections. Tr. 12/20/06, p.42. Staff contends the three-year average for the account yields a total of \$10,563,976, and Staff requests a reduction for customer records and collection expense in the amount of \$376,252, based on that average. Staff Exhibit 3, (Delling Direct), p.14. Using PNM's discovery response to CANM 1-34, Staff calculates that PNM is annualizing slightly more than \$8.84 million for 2006 as compared to PNM's test year total of \$10,964,277. *Id.* Staff claims PNM has not provided sufficient cost data to justify the test year expense. *Id.*

PNM responds that Staff's recommended reduction of \$376,252 in Customer Records and Collection Expense is based on a misunderstanding relating to PNM's response to CANM 1-34, PNM Exhibit 21 (Sategna Rebuttal), p.38. Staff witness Delling testifies she recommended the reduction because she could not understand how PNM arrived at approximately \$10.9 million for the expense. Tr. 12/20/06, p.42. As a result, she "just took a three-year annualized number" and then subtracted the difference from PNM's request. *Id.* On cross-examination, however, Staff witness Delling agreed that some of the customer records and collection activities that were part

of PNM have now been moved to PNMR Services Company. *Id.* at 41. She also agrees that PNM's response to CANM 1-34 only picked up the PNM utility portion and left out the PNMR Services portion. *Id.*

There is essentially no dispute remaining as to PNM's request. If the total excluded costs of \$1,439,093 through August 30, 2006, had been included in PNM's discovery response and Staff had factored the correct number into its projection for PNM's annualized expense, Staff's projected 2006 Customer Records and Collection Expense would have been approximately \$10.99 million, rather than \$8.84 million. PNM Exhibit 21 (Sategna Rebuttal), p.39; Tr. 12/20/06, p.42. Staff agrees that this corrected result of \$10.99 million is nearly identical to PNM's claim for \$10.94 million. Tr. 12/20/06, pp.43-44. As a result, PNM's request for \$10.94 million should be allowed.

9. San Ysidro Abandonment Recovery

PNM is seeking Commission approval to abandon the San Ysidro Facility located in Sandoval County near San Ysidro, New Mexico because the natural gas storage facility is no longer needed. PNM Exhibit 1 (Christopher Direct), pp.14-15. This is so because the reservoir performance is not as effective as when it was new and the facility does not have sufficiently high levels of injection and withdrawal capacity to be effective in meeting PNM's current gas supply needs. Also, PNM has contracted for storage requirements using a third-party storage facility that is more efficient and better meets its current gas supply and balancing needs. *Id.* at p.11. PNM seeks to recover the costs of the abandonment, including environmental reclamation costs. *Id.* at pp.11-15. Abandonment and reclamation costs are estimated to be \$2.1 million. *Id.* at p.14.

PNM is requesting authority to include these costs in Rate Rider No. 14 to be recovered over a one-year period. *Id.*

Staff recommends approving the abandonment of the San Ysidro facility. Staff Brief in Chief, p.21. Staff witness Schwebke supports recovery of the costs in one year through Rate Rider No. 14. He proposes that recovery be capped at the actual cost incurred or the PNM estimate of \$2,091,471, and that PNM return to the Commission for approval of any extra costs of abandonment. Staff Exhibit 2 (Schwebke Direct), pp.7-8. NMIEC does not oppose the recovery of the costs of abandonment, but argues that these should be recovered in rates and not through a rate rider. NMIEC Brief in Chief, pp.11-12.

The AG does not oppose the abandonment, but argues that the cost recovery should be over three years, and that O&M expenses of \$90,197 should be removed from rate base. AG Brief in Chief, pp.38-39. Despite PNM's subsequent agreement to remove all but \$31,529 of O&M, the AG argues against this reduced amount.¹³ AG Reply Brief, p.17. NNSA contends that the recoverable O&M costs should be reduced to \$31,529, (NNSA Brief, p.71), and opposes the recovery of any costs of abandonment, arguing that the facility is not used and useful, is already abandoned or should have been abandoned earlier, or that PNM's recovery of these costs does not satisfy the used and useful test. NNSA Brief in Chief, pp.105-112. NNSA contends that if the Commission allows recovery of abandonment costs, these costs should not be recovered from transportation customers because San Ysidro was used to provide sales service. NNSA Exhibit 1 (Kumar Direct), p.94.

¹³ PNM has agreed to NNSA's suggested amount of O&M costs of \$31,529. PNM Brief in Chief, p.56. PNM mistakenly states that all parties have agreed, too. PNM Reply Brief, p.18.

PNM argues that, contrary to the contention of NNSA witness Kumar, the San Ysidro Storage Facility is not yet an abandoned facility. PNM Exhibit 3 (Sanders Rebuttal), p.4; Tr. 12/13/06, p.96. Instead, PNM is only now proposing to abandon the facility and is requesting authorization from the Commission in this case to do so. *Id.* PNM states that Mr. Kumar's "contention at page 94 of his testimony that the facility has already been abandoned is simply without support. In response to interrogatories NNSA 1-19 and AG 1-129, PNM showed injection and withdrawal volumes during winter months for the years 1996 through 2004 and demonstrated the use of the facility to meet cold day peaks and to balance the pipeline with injections on warmer winter days well into 2004. PNM Exhibit 3, (Sanders Rebuttal), p.5. Since then, as testified to by Mr. Sanders, PNM has been injecting and working the facility through November 2005 in an effort to extract gas from the facility. PNM Exhibit 3 (Sanders Rebuttal), p.5; Sanders Cross, Tr. 12/13/06, p.96." PNM Brief in Chief, p.54.

According to PNM, the San Ysidro facility was used to balance pipelines, and this included balancing for transportation customers. PNM Exhibit 3 (Sanders Rebuttal), pp.5-6. As Mr. Sanders testified, the schedule used by Mr. Kumar (Schedule No. 103 of NNSA Exhibit JK-1) does not provide any information as to extent or size of daily or hourly imbalances by transportation customers and instead only shows monthly receipts, deliveries, and final imbalances for all transportation customers on PNM's system during the year 2005. *Id.* PNM concludes that the information used by Mr. Kumar is insufficient for him to reasonably conclude that the San Ysidro facility was not used to balance transportation customer's needs and is insufficient to refute PNM's testimony as to how the facility was used. Instead, the regulatory methodology

proposed by PNM witness Fernald is more accurate as to the apportionment of these costs between classes of ratepayers. *Id.* at p.7. Mr. Fernald testified that the rates should be allocated to all customers through Rate Rider No. 14 because the facility is used for all customers, including transportation customers. PNM Exhibit 25 (Fernald Direct), pp.39-41.

The Commission concludes that PNM should be granted all regulatory approvals, including those under NMSA 1978, Section 62-9-5, necessary to abandon the San Ysidro facility. The Commission agrees with Staff that the costs of abandonment should be capped at the lower of actual costs or \$2,091,471. Any extra cost will require an application for Commission approval. NNSA's arguments are unpersuasive. All customers should be responsible for abandonment costs. The Commission accepts NNSA's and PNM's suggestion to reduce O&M costs to \$31,529. Finally, the Commission accepts the AG's suggestion that abandonment costs be recovered over a three-year period. PNM asked that a reasonable carrying charge be allowed in this event. NMIEC supports this request. PNM should be allowed a carrying charge equal to its cost of long-term debt, or 6.28%, for these abandonment costs, and it is allowed to recover them through Rate Rider No. 14.

10. Income Taxes

PNM computes its income taxes on a stand-alone basis. It has done so with Commission approval for decades. PNM's revenue requirement includes an allowance for state and federal income taxes. As part of its parent company, PNMR, PNM's gas utility computes its stand-alone taxes as do other divisions. The stand-alone "tax returns are combined by adding them together to form the consolidated tax return. As

the taxpaying entity, PNMR files a consolidated tax return and pays to the Internal Revenue Service ('IRS') the entire current cash tax liability of the group. However, in accordance with the requirements of NMPRC Case No. 3137, PNMR then collects from each entity, its stand-alone current tax liability." PNM Brief in Chief, p.61.

PNM argues that the "stand-alone methodology ensures that rates are determined based solely on the income and expense generated by the gas utility operations. The tax effects of the activities of other divisions of PNM (like electric utility) and other affiliated non-utility companies are excluded. Just as with other expenses, the stand-alone methodology ensures that gas customers pay only for tax expenses related to gas operations and are not charged for the costs associated with other non-gas or non-utility operations." *Id.* at p.60. PNM points out that in Case No. 3137, the Commission approved formation of PNMR, the holding company, required PNMR to file a consolidated tax return and also required that PNM's payment to PNMR for income tax be limited to PNM's share of the current income tax liability of PNMR. *Id.*

In this case, Staff used the same stand-alone method as PNM "to calculate the net allowable federal and state taxes ... for use in the cost-of-service." Staff Exhibit 3 (Delling Direct), p.21. Based on its proposed reductions to PNM's rate base, cost-of-service and return on equity, "Staff decreased net allowable taxes from \$15,253,627 to \$11,378,175 ... a reduction of \$3,875,452...." *Id.* at p.22. The AG and NNSA would further reduce this amount.

The AG and NNSA both criticize PNM's use of the stand-alone methodology in computing income tax expense. AG Brief in Chief, pp.41-42, NNSA Brief in Chief, pp.71-79; NNSA Reply Brief, pp.16-19. Both argued that because PNMR files a

consolidated tax return, that the appropriate tax methodology is the consolidated basis. AG Exhibit 1 (Crane Direct), p.69; NNSA Exhibit 1 (Kumar Direct), p.62. Ms. Crane argues that the consolidated income tax methodology is consistent with NMPRC Case No. 3137. *Id.* at pp.69-70. Mr. Kumar contends that the Commission's Order in Case No. 3137 requires the income tax computations be on a consolidated basis. *Id.* at p.71. PNM responds that a change in method by the Commission would require both sound reasons and advance notice, prior to this case.

PNM points to a long line of Commission cases, including Case Nos. 2662 and 2567, approving PNM's use of the stand-alone method. PNM Brief in Chief, p.60. Significantly, in NMPRC Case No. 03-00017-UT, decided in 2004 Staff witness Gary Brenner testified that:

The 'stand-alone' methodology bases the tax calculation on those items of income and expense that relate directly to the operation of the utility (as opposed to the 'consolidated tax' approach which attempts to utilize the tax laws benefits associated with non-utility business to lower utility rates). The Commission has approved the 'stand-alone' methodology in all previous cases.

PNM Brief in Chief, p.59.

While that case was settled, and the Commission did not approve any specific issue in that case (other than the \$20,000,000 rate increase agreed to by the parties), it is evident that a highly respected Staff accountant relied on the stand-alone method years after the Commission approved the formation of PNMR and in doing so required the holding company to file a consolidated income tax return. In any event, the evidence and argument provided by the AG and NNSA in this case do not justify a departure from the Commission's use of the stand-alone income tax methodology.

NNSA does not object to PNM's normalization of deferred federal income tax as required by Section 168 of the IRC, but does object to using the same normalization methodology to compute state income taxes. NNSA Exhibit 1 (Kumar Direct), pp.60-61; NNSA Brief in Chief, pp.79-81; NNSA Reply Brief, pp.20-21. PNM points out that the flow-through methodology is prohibited by Section 168 of the IRC for deferred federal income tax related to public utility property. PNM argues there is no theoretical difference between deferred state income tax and deferred federal income tax and their treatment for ratemaking purposes. The normalization accounting methodology, according to PNM, is required by GAAP as set forth in SFAS 109. PNM Brief in Chief, p.64.

PNM concludes that using the flow-through method results in income taxes being accounted for with "the accrual, rather than the cash method. Its use in a ratemaking proceeding ensures that ratepayers are charged only for the taxes that relate to the income and deductions included in the period for which cost-of-service revenue requirements are being calculated. Thereby, ratepayers in one period do not benefit unjustly at the expense of ratepayers in another period, merely due to the effect of temporary differences." *Id.*

PNM responds to Mr. Kumar's proposed flow-through method by pointing out that, according to PNM witness Harland, Mr. Kumar's approach "records only the current income tax expense due in the current period. No deferred component is recorded. This results in a mismatch in the timing of the tax expense and the underlying income and deductions." *Id.* at p.65. The Commission concludes that PNM can continue to use a normalization methodology for computing deferred state income tax.

11. Dues

PNM seeks to recover \$142,613 it pays in dues to the American Gas Association ("AGA") and \$23,000 it pays in dues to the Western Energy Institute ("WEI"). The AG would disallow 20% of these dues, NNSA would disallow 51% and Staff would disallow 50%. PNM Brief in Chief, pp.65-66; Staff Exhibit 3 (Delling Direct), p.14. PNM opposes any reduction to its requested full recovery of \$165,613. PNM Reply Brief, p.20.

PNM points out that Commission Rule 350.10 allows recovery of dues "if the dues contribute to the professional education and standing of the Company's employees [and] the utility [is required] to affirmatively demonstrate that the expenditures are reasonable and adequately accounted for...." PNM Brief in Chief, p.66.

Expenses for lobbying are not recoverable. PNM witness Brunt stated that only 1.88% of AGA dues were used for lobbying. PNM Brief in Chief, p.67; PNM Exhibit 5 (Brunt Rebuttal), p.2. When asked where on the AGA budget the 1.88% for lobbying is reflected, PNM witness Brunt's initial response was that "It's under policy, planning and regulatory affairs", and with regard to the specific category of lobbying and the exact figure, her next response was "[t]hat is what I was told by AGA, received that information from them." Tr. 12/13/06, p.132. PNM did not provide written documentation in support of its claim that lobbying was only 1.88% of the AGA budget.

Staff provided the following testimony on this aspect of PNM's request. "Staff found in exploring AGA's official website that it is heavily involved ... in advocacy and legislative matters pertaining to the gas industry. [PNM] is deficient in meeting its burden of proof that these efforts by AGA 'are not directly or indirectly supporting utility

... related lobbying efforts ...', which is not allowed for cost-of-service recovery pursuant to 17.3.350.11 NMAC." Staff Exhibit 3 (Delling Direct), p.15. Staff recommends a total recovery of \$94,305.

The Commission agrees with Staff that PNM has not met its burden of proof. In several past cases, the Commission disallowed 46% of PNM's payments for AGA dues for media and government relations. Recommended Decision, Case No. 2147, p.68. In this case, rather than disallowing 50% as requested by Staff, the Commission concludes that the proper disallowance is the 39.8% of the AGA budget for public affairs, policy, planning and regulatory affairs. Tr. 12/13/06, p.127. PNM has not met its burden of proof as to its full request for this budget category. As a result, PNM is allowed to recover the \$23,000 it paid to WEI and 60.2% of the dues of \$142,613 it paid to the AGA, for a combined total of \$108,853.

12. Advertising

PNM asks to recover \$1,329,825 for informational advertising expense¹⁴, as allowed by 17.3.350 NMAC ("Rule 350"). PNM describes two categories of expense: (1) customer communications relating completely to natural gas service and (2) expenses for both natural gas and electricity customers, with an allocation based on PNM's Cost Allocation Manual ("CAM"). Much of the total expense is for PNM's weatherization kits, weatherization DVD and related increased advertising during the fall of 2005 when natural gas prices increased sharply. PNM Brief in Chief, pp.68-71; Reply Brief, p.22.

¹⁴ The AG states that "PNM has agreed that \$5,332 of its advertising cost claim was inadvertently included. AG Exhibit 1 (Crane Direct), p.64. Ms. Crane's schedule relating to these costs is Schedule ACC-23." AG Brief in Chief, p.40.

PNM sets out in full the provisions of Rule 350 concerning advertising expenses. PNM Brief in Chief, p.70. The pertinent provisions include the definition of “Advertising Expenses” as:

all expenses made for the development, publication, and/or dissemination of information to a utility’s ratepayers, the public at large, or utility stockholders including, but not limited to, publications in newspapers, magazines, information for use by the electronic media, bill enclosures, or other mailings....

The central feature of the definition is clearly “information”. Other pertinent provisions of Rule 350 provide that “advertising expenses which may be properly included in the cost-of-service shall be that advertising which is reasonable in amount and which: ...

2. Advocates to ratepayers through factual data and advice their conservation of energy resources and reduction of peak demand; [or]

3. Explains utility billing practice, services, and rates to ratepayers;”

Paragraph 3 covers traditional bill inserts and similar communications. Paragraph 2 covers media advertising and, in the present case, weatherization DVDs prepared by PNM in response to extremely high natural gas prices. The DVDs satisfy the three requirements found in the definition and paragraph 3 concerning “information” and “factual data and advice”. While the DVDs satisfy all three of these requirements, the free weatherization kits distributed by PNM do not. The kits lack “data” and “advice”. PNM’s assertions that the items in the kits satisfy these two requirements are not persuasive. PNM Reply Brief, pp.21-22. The advertising that informed ratepayers that the kits were free and available does not suffer from these shortcomings and their

expenses are recoverable. The kits themselves were not information, and would create goodwill, another characteristic that demonstrates their expense is not recoverable as an advertising expense.

The AG asked the Commission to consider the entire amount of \$332,972 for the DVDs and weatherization kits in the case relating to PNM's gas efficiency programs, Case No. 05-00261-UT. The Commission accepts the AG's request concerning the \$238,481 weatherization kit expense. PNM will have an opportunity to seek recovery of those costs in Case No. 05-00261-UT or in another case.

As to the DVD expenses of \$94,491, the Commission declines to follow the AG's suggestion, because these expenses are allowable. The Commission does not accept Staff's suggestion to reduce the DVD amount in proportion to the percentage of gas customers to total customers. PNM Brief in Chief, p.61. These DVDs were part of an overall response to a spike in natural gas prices. Their cost is recoverable from natural gas customers.

NNSA initially asked the Commission to exclude \$335,000 of PNM's request. NNSA Exhibit 1 (Kumar Direct), pp.53-54. In its Brief in Chief (pp.64-67), NNSA increased this amount to \$820,000. NNSA's position is a general attack on advertising and is not persuasive.

Finally, Staff witness Delling contests PNM's allocation of allowable expenditures for certain PNM publications. Staff Exhibit 3 (Delling Direct), pp.17-18. She recommends a decrease in advertising expense of \$23,815 "based on percent of relevant text and information related to Gas Services." *Id.* PNM opposes her position, relying on its rebuttal testimony. PNM Brief in Chief, p.75. PNM concedes that it lacks

information on “which types of customers”, gas or electric, receive its publications and relies on its CAM allocation of 53.26 percent. Staff witness Delling’s analysis is more specific and will be accepted by the Commission. Accordingly, the cost-of-service will be reduced by an additional \$23,815.

13. Worker’s Compensation Reserve

PNM initially claimed a “worker’s compensation expense of \$965,275 for the base period by averaging the worker’s compensation expenses incurred in 2002, 2003 and 2004. Sategna Direct, p.18.” PNM Brief in Chief, p.76. PNM later agreed to reduce this expense to \$895,256 based on the concerns of other witnesses. PNM Brief in Chief, p.77.

PNM did not use the 2005 based period amounts. Staff witness Delling reversed a 2005 actuarial adjustment out of the 2005 expense, then averaged the years 2003 through 2005, which results in her recommended expense of \$792,922. Staff Exhibit 3 (Delling Direct), p.10. NNSA used 2006 data through May in combination with 2003 through 2005 expenses and recommend \$801,010. NNSA Brief in Chief, pp.56-57.

The AG’s witness testified that PNM’s response to a discovery request concerning “the unusually high workers compensation cost ... in 2004 [was] that the cost was ‘higher in 2004 than in the previous two years because of an end of year adjustment ... similar in nature to the ... adjustment at the end of 2005.’ Thus, in determining its multi-year average, the Company included the 2004 adjustment, which increased the overall average, but elected to exclude the 2005 adjustment, which would have reduced the multi-year average. The fact is that workers compensation costs do vary from year-to-year and that sometimes these variations are substantial” AG

Exhibit 1 (Crane Direct), p.65. AG witness Crane recommended using “a 4-year average of workers compensation costs, from 2002 to 2005, which would include both the high 2002 year and the low 2005 year. This is more reasonable than the company’s approach. AG Exhibit 1, (Crane Direct), p.66.” AG Brief in Chief, p.41. Her 4-year average is \$541,350, which is a \$353,907 reduction, excluding taxes, from PNM’s revised request. *Id.* The Commission accepts the AG’s recommendation as the most reasonable treatment of this issue.

14. Pipeline Integrity Costs

PNM claims \$750,000 for pipeline integrity costs. PNM Brief in Chief, pp.77-78. In support of its request, PNM states the following. “The parties have agreed on \$750,000 at [sic] the amount that should be allowed as an adjustment for pipeline integrity costs. Crane Cross, Tr. 12/15/06, pp.236-237.” PNM Brief in Chief, p.78. An examination of the transcript shows an incomplete agreement at most.

“Q. ... We have since accepted your position that was in error and so we are now consistent with that the amount in rates should be based on \$750,000?

A. Yes, I believe the AG and the Company are consistent with regard to that issue.”

Tr. 12/15/2006, pp.236-237.

AG witness Crane agreed that the amount in rates should be based on \$750,000, not, as PNM concludes, that \$750,000 is the amount that should be in rates. Her direct testimony shows the AG’s complete position.

As shown in PNM Exhibit RAM-2, page 1, the Company budgeted \$665,000 for these costs in 2005 and projects \$750,000 of costs in both 2006 and 2007. In the base period, PNM actually spent \$334,550, well below its

projected \$665,000. Moreover, according to PNM Exhibit RAM-2, the \$750,000 projected for 2006 and 2007 is not incremental to the annual amount spent in the base period, but represents the total projected annual costs for 2006 and 2007 related to the program. Since the base period already includes actual costs of \$334,550, the Company's adjustment to increase costs by \$750,000 is overstated. This is because PNM did not reduce its adjustment to account for costs already reflected in the base period.

Therefore, at a minimum, the NMPRC should make an adjustment to reduce the Company's claim by the amount of pipeline integrity costs already reflected in the base period. Since the base period already reflects \$334,550 of pipeline integrity costs, the Company's adjustment should be limited to \$415,450, the difference between the projected amount of \$750,000 and the base period actual costs.

AG Exhibit 1 (Crane Direct), p.53.

AG witness Crane went on to describe how much PNM has spent on pipeline integrity costs in the first eight months of 2006. "PNM spent \$294,097 through August 2006 on pipeline integrity programs. Thus, it appears that the Company's 2006 cost projection of \$750,000 may be overstated by a significant amount. Accordingly, the NMPRC may choose to make a further reduction to the Company's claim, to reflect the fact that PNM is unlikely to meet its budgeted operating and maintenance expenses associated with pipeline integrity programs in 2006." AG Exhibit 1 (Crane Direct), p.54.

The record shows that PNM spent \$334,550 in 2005 (the base period) after projecting \$665,000 for 2005. PNM then budgeted \$750,000 for pipeline integrity costs in 2006, and actually spent \$294,097 in the first eight months of 2006. Extrapolating from this last figure gives a full calendar year amount of \$441,145.

In the past, the Commission has expressed serious reservations concerning, and consequently declined to use, budgeted amounts. "However, the plant additions were

merely projections and budgeted items, not known ones. As it turns out, they were not measurable with any degree of accuracy. If anything regarding the projections is known and measurable, it is that they did not come to fruition before the end of calendar year 1987.” Recommended Decision, Case No. 2147, p.22. In the present case, the Commission will not use the budgeted amount of \$750,000.

As was true in 2005, the actual 2006 figures show that budgeted amounts have not been accurate or useful. Only because of the importance of these projects to the public safety, and because they are undertaken to comply with a specific legal requirement, the Commission will consider the 2006 data in the record and rely on the actual expenditures for the first eight months of 2006. As a result, instead of using the test period 2005 figure of \$334,550, the Commission will allow PNM to use the higher amount of \$441,145, but not the budgeted amount of \$750,000.

15. Litigation Expense

PNM is seeking recovery of \$980,168 in litigation expense incurred during the base year.¹⁵ PNM Exhibit 6, (Boyle Direct), p.7. The expense involves tort claims, human resource claims, commercial litigation and FERC and Commission cases. PNM expects that these types of cases will continue in the future. PNM Brief in Chief, p.78.

NNSA asks the Commission to exclude a large part of these expenses. The AG does not object to full recovery of the amount, but asks that FERC litigation costs be recovered over five years.

¹⁵ An errata notice to Mr. Boyle’s testimony filed on August 23, 2006, shows at PNM Exhibit GWB-6 Revised, the \$980,167.61 total and amounts by category, including \$284,305.42 for FERC matters and \$394,034.89 for Human Resource matters.

NNSA asks the Commission to exclude \$267,073 related to PNM's 2002 layoffs as a non-recurring expense. NNSA Exhibit 1 (Kumar Direct), pp.43, 46. PNM witness Boyle responds that in these and other cases PNM and PNM Resources "are a party in the normal course of business." PNM Exhibit 7 (Boyle Rebuttal), p.2. As PNM witness Boyle explained: "Based on that reasoning, a public utility could not recover litigation expenses for any lawsuit, because each lawsuit is unique and occurs only once." *Id.*

NNSA objects to other expenses based on the same reasoning and also argues that certain FERC case expenses should not be included in the Transportation Service cost-of-service because, according to NNSA, these cases "mainly benefit the Company's sales customers...." NNSA Exhibit 1 (Kumar Direct), p.44.

PNM's Reply Brief (p.24) demonstrates that NNSA's Brief in Chief (p.59) left out several words from a quoted portion of PNM witness Boyle's Rebuttal Testimony at page 6. The missing words show that PNM's FERC cases affect transportation as well as supply customers. NNSA's position on this issue would not prevail in any event.

The Commission concludes that the total of PNM's litigation expenses is allowable for recovery. PNM's testimony shows that there has been a recent increase in its FERC litigation. PNM Exhibit 7 (Boyle Rebuttal), p.6; PNM Brief in Chief, pp.82-83. PNM concluded as follows in its Brief in Chief, p.83: "Given the frequency of PNM's intervention in other FERC gas utility matters, the three-year amortization period proposed by PNM is appropriate." Even if PNM had not made this proposal, a three-year amortization "conforms to usual ratemaking policy of the Commission." Recommended Decision, Case No. 2147, p.60. The recent increase in PNM's FERC litigation does not justify a departure from this policy.

The Commission concludes that PNM's FERC litigation base year expense of \$284,305 should be amortized over three years, as should its \$267,073 expense related to 2002 layoffs. The record shows expenses in 2005 concerning 2002 layoffs; it does not reflect such layoffs occurring annually. It is therefore proper to allow recovery of these expenses over three years as well. The remaining categories and amounts of litigation expense are representative of litigation that occurs on a regular basis and its recovery is allowed annually.

III. Rate Design

The design of rates is one of the more difficult and subjective tasks that confronts the Commission in a rate proceeding. Often the diverse interests can agree on many items in the cost-of-service only to come in conflict when it comes to advocating what rate class pays what amount. Further, rate design is a strange mix of general economic principles and conflicting ideas of what is in the public interest. The ultimate decision is judgmental in any event and is often criticized by many with vested interests in the outcome.

The New Mexico Supreme Court has recognized that "there is a great measure of public policy that enters into the apportionment of rates...." *Mountain States*, 90 N.M. at 333. The Court also recognized that the "Commission's discretion on public policy issues" is involved in the apportionment. *Id.* Further, the Court has concluded that the exercise of the Commission's discretion on public policy matters may result in subsidies. The Court stated that "determining the level of subsidies, if any, is a Commission function...." *Id.* at p.338. Also, the Public Utility Act prohibits unreasonable discrimination as between rate classes. NMSA 1978, Section 62-8-6 (1993).

The Court has also recognized the “art” involved in the design of rates in addition to the “science.” The Court has held that: “Extreme nicety in the allocation [of rates] is not required, but only reasonable measures are necessary.” *Id.* at p.339 (citations omitted). Quoting from *Hope*, the Court declared: “It is not the theory but the impact of the rate order that counts....” *Mountain States*, 99 N.M. at p.8.

The Commission has held that there are two major objectives to be accomplished in rate design:

First, the design should provide stability of earnings for GCNM and thus an opportunity to earn its allowed return. Second, the impact of the required rate increase should be minimized on the customers (citations omitted). These are the objectives that the Commission continues to endorse while attempting to set rates that are fair, just and have a reasonable relationship to the cost of providing the service.

NMPSC Case No. 2147, Recommended Decision of the Hearing Examiner, p.86 (citing to the Final order in NMPSC Case No. 1787).

1. Weather Normalization

The consumption of natural gas is highly weather sensitive. The purpose of a “weather normalization adjustment” in a rate case is to establish rates that reflect normal revenue levels by normalizing weather data for the test period. If the weather during the test year was colder or warmer than normal, the amount of natural gas used, and thus the level of revenues, could be overstated or understated. Tr. 12/19/06, p.24.

Ten years ago, in Public Utility Commission Case No. 2662, the Commission selected a thirty-year period of three fixed decades supported by the AG over the ten-year period supported by PNM and Staff and recommended by the Hearing Examiner. The Supreme Court upheld the Commission on this issue, while reversing on several

others. *PNM Gas Services v. New Mexico Public Utility Commission*, 129 N.M. 1, 1 P.3d 383, 2000-NMSC-012, ¶78. (“Because ratemaking is prospective in nature, the Commission, in an attempt to accurately predict a natural gas utility’s revenue requirement based on past activity, utilizes a weather normalization adjustment to minimize the potentially distorting effect of unusually high-or-low-usage test years. The weather normalization adjustment consists of an average weather calculation based on long-term weather data.”).

In Case No. 2662, the Commission concluded that the longer 30-year period “will tend to better capture the variability of weather.” Case No. 2662, Final Order, p.28. More recently, in a non-precedential settlement of PNM’s last natural gas rate case (Case No. 03-00017-UT), the ten-year period was agreed on by the parties and is in use. The Commission’s past approval of that settlement does not bind the parties or the Commission in the present rate case.

In this case, PNM proposes a ten-year weather normalization adjustment to reflect what it believes is normal weather. PNM Ex. 23 (Gutzler Direct), p.2. PNM witness Gutzler has an M.S. in Atmospheric Science from the University of Washington and a Ph.D in Meteorology from M.I.T. He is a Professor of Meteorology and Climatology at the University of New Mexico. *Id.* at p.1. The AG and NNSA witnesses lack any formal training in these areas. PNM Brief in Chief, p.89. Staff supports PNM’s proposed most recent ten-year adjustment for weather. Staff Exhibit 5 (Sisneros Direct), pp.22-23.

The AG advocates the use of the fixed thirty-year adjustment which would reduce PNMGS’ proposed revenue requirement. NNSA also supports a 30-year period. Using

the fixed 30-year period of 1970-1999 instead of the most recent 10 years would decrease PNM's revenue requirement by over 6.7 million dollars. NNSA Brief in Chief, p.49. Both the AG and NNSA are willing to use the most recent thirty-years rather than the fixed three decades of 1970-1999.

The AG and NNSA believe that thirty-year data is superior because it incorporates more data points, including a greater number of high and low points, and better reflects the possible range of heating degree days as well as temperature patterns. Further, the AG points out that this Commission has long held that thirty-year weather normalization is appropriate unless there is justification for doing otherwise. Re Southern Union Gas Company, 12 P.U.R. 4th 219 (1975). The AG also contends that a large number of commissions accept and use the thirty-year normalization, referring the Commission to: Re Connecticut Natural Gas Corporation, 148 P.U.R. 4th 239, 250, 259 (1993); Re Oklahoma Natural Gas Company, 56 P.U.R. 4th 183, 218, 219 (1983); Re Kokomo Gas and Fuel Company, 88 P.U.R. 4th 56, 60 (1987); Re Peoples Gas Light and Coke Company, 63 P.U.R. 4th 304, 317-318 (1984); Re Mountain Fuel Supply Company, 149 P.U.R. 4th 36, 69 (1994).

PNM used weather data from the National Oceanographic and Atmospheric Administration ("NOAA") for Albuquerque and from local weather reporting services in five other locations throughout the areas in which it provides service. PNM Exhibit 23 (Gutzler Direct), p.3. Dr. Gutzler testified that while 30-year weather is a climate norm, the NOAA has not established a 30-year standard for regulatory purposes. PNM Exhibit 24 (Gutzler Rebuttal), p.4. The AG and NNSA witnesses testified in favor of the traditional 30-year period, but their reasoning was general in nature. They did not

demonstrate that 30 years has been more accurate than ten years over any recent time frame, particularly the last ten years. In response, Dr. Gutzler pointed out that “in the presence of a trend in climate there will be a limit to the usefulness of including additional data far removed in time from the present.” PNM Exhibit 24 (Gutzler Rebuttal), p.3. He testified that there has been a fairly consistent downward trend in heating degree days due to a warming trend in recent decades. Id.; Tr. 12/19/06, pp.41-45.

He agreed that a longer period is more stable, “but that is only useful in the absence of a long-term trend.” Tr. 12/19/06, p.56. He concluded that the “warming trend is real and that there is no basis for assuming that it will end.” Id. at p.53. His testimony was candid and credible. He agreed that the success of any predictive model in one time period does not guarantee that it will have the same level of success over the next time period. Id. at p.48.

The question to be decided is what time frame to use to normalize weather. PNM stated that it “is not simply an exercise in finding a normalization standard with some evidence to support it, but an effort to find the better or best normalization standard to result in more accurately set revenue levels.” Brief in Chief, p.89.

There is no ready made answer. As Dr. Gutzler explained, the American Association of State Climatologists concluded that “no single averaging period has been demonstrated to be optimal”, 30-year averages lack “special predictive properties” and “various investigators find that periods between 5 years and 35 years best represent climatic averages for different regions, different climate variables, and ... different lengths of future time to which the expected values apply.” PNM Exhibit 23 (Gutzler

Direct), p.7. For this rate case, PNM informed him that rates are expected to remain in place for three years. Tr. 12/19/06, p.49.

Three main facts emerge from Dr. Gutzler's testimony at the hearing: (1) the most recent ten years approach does a much better job than a fixed three decade (1970-1999) period of predicting temperatures and heating levels in recent years due to a warming trend, (2) he did not study whether some other period (15, 20, 25 years) could do better and (3) PNM only asked him to study and compare 10 and 30 year periods.

Dr. Gutzler's testimony described his analysis of temperature "data over the past half-century at sites representative of the major climate regimes and population centers in PNM's service area in New Mexico. I investigated whether 10-year or 30-year averages of annual [heating needs due to average of daily high and low temperature] provide a better basis for estimating expected values of annual heating degree days for the next several years, for the purpose of estimating the climatic component of expected natural gas sales." PNM Exhibit 23 (Gutzler Direct), p.2.

Based on his study and analysis of the pertinent data, Dr. Gutzler reached the conclusion that the most recent 10 years does a better job than 30 years (3 fixed decades) of estimating heating needs over the "target period of the past 10 years (1996-2005)." *Id.* at p.5. Reviewing past temperature data, he calculated the accuracy of the three fixed decade approach (1970-1999), a fixed one decade approach (1981 to 1990 or 1991 to 2000), or the most recent 10 years in predicting total heating degree days for his target period of 1996 to 2005. He concluded that the "30-year climatological

averaging period consistently and substantially overestimates average annual [heating degree day] totals during the past ten years at all six sites.” *Id.* at p.6.

His overall conclusion was that the most recent 10 years is better than a fixed decade, which is better than a 30-year average. Tr. 12/19/06, pp.50, 38. His testimony showed that the most recent 10 years is better at estimating future temperatures and heating degree days than these other periods he examined. *Id.* at p.59.

Dr. Gutzler stated that he did not examine any of the intermediate periods between 10 and 30 years. *Id.* PNM asked him to compare only 10 years to 30 years. *Id.* at p.33. PNM did not ask him to look at and compare intermediate time frames such as 15, 20 or 25 years. *Id.* at pp.33-34.

He testified that it is “quite possible” a most recent 15 or 20 year period would also do a much better job than the 30 year period. *Id.* at pp.53-54. And he testified that there is “no single number that can be represented as an optimal averaging period to establish current climatic conditions” *Id.* at p.57. While supporting PNM's proposal, Staff witness Schwebke testified at the hearing that the number of years chosen for weather normalization is less important than the consistent use of the period chosen. Tr. 12/20/06, p.20.

Dr. Gutzler's testimony provides a sufficient record to conclude that the most recent 10-year period does a much better job than the Commission's traditional fixed three decades approach. Accordingly, the fixed three decade approach should no longer be used. While the decision to replace the fixed three decade standard is easy, its replacement is not as readily made, because no time period has been established as optimal and Dr. Gutzler did not study intermediate time periods of 15, 20, and 25 years.

In short, PNM has met its burden of proof that the most recent 10 years is better than the fixed three decade period, but not that the most recent 10-year period is the best period available.

At the time PNM next files a natural gas rate case, it should, at a minimum, include studies of the three intermediate time periods (15, 20 and 25 years), as well as of the most recent 10 and 30-year periods. The studies should include detailed documentation, with an explanation of all statistical techniques and terminology used. Copies of chapters from published textbooks or treatises on statistics explaining the techniques and terminology used will be appreciated.

Because a longer time frame has the ability to better represent the potential variability of weather, we conclude that until PNM's next natural gas rate is decided, a period longer than the most recent 10 years should be used. We can not know in advance which time period, including one of the three intermediate time periods of 15, 20 or 25 years, will emerge as the best, but until that study is made we conclude that one of the 15, 20 or 25 year periods could be used, and that the most recent 15-year period should be used.

Dr. Gutzler agreed that it would be better to not use 1970s data, as the fixed three decades (1970-1999) approach does. Id. at p.61. As Dr. Gutzler explained, the likelihood that a shorter period such as 20 or 15 years will more accurately estimate future temperatures than 30 years "sounds reasonable ... I don't have numbers for you. The way to assess that, of course, would be to look at the data and generate those percentages." Id. at p.65. That, of course, remains to be done.

2. PNM's Decoupling Proposal

PNM proposes in this case to break the historic link between its sales volumes and the revenues it receives. It would do so on a per customer basis. Tr. 12/14/06, pp.85, 158-159. Quite simply, if an existing residential customer reduces their natural gas use by half, under PNM's decoupling proposal that customer would still pay the same full amount to PNM that the customer paid when PNM delivered twice as much gas to the customer. Tr. 12/14/06, p.233. The customer would always pay for the actual amount of natural gas used at the market price¹⁶, but their individual conservation efforts would not affect the 1/3 of their bill that covers PNM's services. PNM's revenues and profits depend entirely on its authorized charges for these delivery (transmission and distribution) services.

As it stands now, about one third of a typical customer's bill is for the basic services PNM provides of delivering natural gas through its system to its customers. PNM's proposal, variously called decoupling or a Consumption Normalization Adjustment ("CNA") would be placed in its rates via proposed Rate Rider 16 ("RR 16"). It would only apply to PNM's residential and small commercial customers. It would not apply to PNM's other rate classes, such as large commercial and industrial customers. These large customers are NMIEC's membership and even though decoupling would not apply to its members, NMIEC's primary focus in this case is its opposition to decoupling.

¹⁶ PNM does not make any profit on the sale of natural gas to its retail customers. PNM charges its customers exactly what PNM pays for the gas. There is no markup, no profit, just an exact pass-through of PNM's costs. The mechanism for this arrangement is the Purchased Gas Adjustment Clause or PGAC. Typically, the gas charge or commodity portion is about 2/3 of a residential customer's bill. The commodity price of natural gas is not regulated and reflects the operation of market forces. Tr. 12/14/06, p.174.

Every intervenor group in this case that represents PNM's customers opposed decoupling or RR 16. They are the AG, NNSA, CANM, NMIEC (all of whom testified against the proposal) and UNM, whose witness did not testify concerning decoupling, but UNM argued against decoupling in its Briefs. NRDC/SWEEP and Staff supported decoupling, but Staff expressed concern about the legal issues of whether RR 16 constitutes retroactive ratemaking and whether it is consistent with the prior hearing requirement before changing rates of NMSA 1978, Section 62-8-7(E). Also, Staff suggested that the reduction of risk for PNM that decoupling would cause should be reflected, if decoupling is approved, in PNM's allowed return on equity.

In support of its decoupling proposal, PNM relies in large measure on the Efficient Use of Energy Act ("EUE"). NMSA 1978, Section 62-17-1, *et seq.* (2005). The Act provides in Section 62-17-3 (emphasis supplied) that: "It is the policy of the Efficient Use of Energy Act that **public utilities ... include cost-effective energy efficiency and load management investments in their energy resource portfolios and that any regulatory disincentives that may exist to public utility investments in cost-effective energy efficiency and load management are eliminated.**"

The EUE requires that the Commission determine whether there are any regulatory disincentives to such utility investments and if the Commission finds that there are, the Commission is further required to eliminate such regulatory disincentives. "The commission shall identify any disincentives or barriers that may exist for public utility expenditures on energy efficiency and load management and, if found, ensure that they are eliminated in order that public utilities are financially

neutral in their preference for acquiring demand or supply-side utility resources.” NMSA 1978, Section 62-17-5(F) (2005) (emphasis supplied).

The Commission has not made any findings that such barriers or disincentives exist. PNM and NRDC ask the Commission to do so in this case. Before reaching that question, we turn to PNM's central position concerning decoupling.

PNM claims that its decoupling proposal is necessary¹⁷ to carry out the purposes of the Efficient Use of Energy Act. The policy of the EUE requires PNM, and other utilities (gas and electric), to make certain types of energy efficiency and load management investments and it requires the Commission to first determine if any disincentives or barriers exist to such utility investments, and second, if found, to eliminate them so “public utilities are financially neutral in their preference for acquiring demand or supply-side utility resources.”

PNM argues it needs decoupling to eliminate the disincentive it now has to reduce its sales volumes. PNM depends on the sale of a certain volume of natural gas to recover its fixed costs. The customer charge for residential customers covers about 45% of PNM's fixed costs and is imposed regardless of the amount of gas used. Tr. 12/14/06, p.162. PNM points out that if it invests in energy efficiency or load management programs, customers will reduce their natural gas use and thus reduce PNM's revenues, recovery of fixed costs and consequently its profits. PNM's primary witness concerning decoupling, Mr. Feingold, testified that “proposed Rate Rider No. 16 should be viewed as a means to eliminate disincentives associated with PNM's efforts

¹⁷ PNM's decoupling witness agreed that RR 16, PNM's proposal, is “not the only one, but it's the most effective one to eliminate the ... disincentive which is the throughput incentive that a utility has.” Tr. 12/14/06, p.158.

to promote energy efficiency and conservation programs such as its Residential Gas Energy Efficiency Program....” PNM Exhibit 15 (Feingold Direct), p.5.

PNM Vice President Melvin Christopher explained PNM's claim of an existing incentive for increasing sales volumes (or throughput of natural gas) and corresponding disincentive to invest in programs that reduce customers' use of gas.

With throughput we make more money. With a decrease in throughput it hits our earnings and we don't make money. That is a significant disincentive. The efficient use of energy act is encouraging a reduction in usage by customers and encouraging the company or requiring the company to put into place programs that will lead to a decrease in throughput. That is a clear disincentive and a clear disincentive for the company....

Tr. 12/13/06, p.64.

As written, RR 16 would protect PNM from any reduction in consumption due to ratepayer actions, including those completely unrelated to PNM's energy efficiency programs such as customer reaction to the increased price of gas, general economic conditions, and customer actions such as turning down the thermostat. NMIEC Exhibit 3 (Dirmeier Direct), pp.11-12.

PNM witness Feingold admits that his decoupling proposal, RR 16, will adjust rates on a monthly basis for fluctuations in PNM's actual gas volumes which are “caused primarily by the energy efficiency and conservation efforts of [PNM's] customers and variations from ‘normal’ weather.” PNM Exhibit 15 (Feingold Direct), p.4. PNM's own recent conservation and efficiency efforts are not even one of the causes of the significant decline in gas use per customer over the last ten years, because PNM had no gas efficiency program in place during this time. Tr. 12/14/06, pp.141-142.

As a result, PNM would be automatically compensated for any reduction in per customer use, including the customer response to high gas prices. Tr. 12/14/06, p.150. The EUE was enacted, NNSA, NMIEC, the AG and UNM argue, to eliminate disincentives to public utility expenditures on energy efficiency and load management programs, not to give PNM an automatic rate adjustment mechanism to compensate it for lost revenues no matter what caused the loss.

Mr. Feingold admitted at the hearing that the need for his revenue decoupling mechanism had two causes, “the margin losses associated with declining use per customer and the need to eliminate the throughput incentive....” Tr. 12/14/06, p.222. Despite selling less natural gas per customer, PNM's overall revenues have increased along with customer growth. Between 1998 and 2003, PNM added over 37,000 new customers and its total revenues from residential customers exceeded its corresponding rate case revenue by over \$34 million. *Id.*

PNM witness Feingold states that Rate Rider 16 is the recommended ratemaking solution to ensure PNM's financial performance is not negatively impacted by the actions of its customers in response to its Residential Gas Efficiency Program and additional energy efficiency program it expects to implement in the future. PNM Exhibit 15 (Feingold Direct), p.5. But PNM witness Christopher acknowledges that the purpose of the decoupling mechanism is to compensate PNM when “customers practice conservation, implement energy efficiency measures, or consume less gas in response to warmer winter temperatures...” PNM Exhibit 1 (Christopher Direct), p.8. And PNM witness Fernald recognized that the “first and most likely contributor to reduced

consumption is the very sharp increase in natural gas prices....” PNM Exhibit 25 (Fernald Direct), p.35.

PNM’s solution to its posited disincentive is overbroad. Assuming PNM has such a disincentive, and assuming the Commission were to agree and require its elimination in this case, the EUE requires the elimination of “any disincentives or barriers” to the required utility investments. The Act does not require, or even contemplate, insulating PNM’s revenue recovery from any and all causes. The EUE mentions “utility expenditures on energy efficiency and load management.” Section 62-17-5(F). It requires, if a disincentive is found, that utilities be made financially neutral as to whether they prefer “demand or supply-side utility resources.” The Act does not require that they receive the same amount of money from a customer who chooses to use less gas.

The scope of PNM’s decoupling proposal is remarkably broad. At the hearing, PNM witness Feingold agreed that his Rate Rider 16 is much broader than protecting PNM’s financial performance from customer response to PNM’s residential energy efficiency program. Tr. 12/14/06, p.142. Decoupling protects PNM regardless of why per customer revenues decrease. *Id.* at pp.160-161. Mr. Feingold agreed that the EUE does not mention decoupling or protecting a utility from weather risk (*Id.* at p.68), or lost sales due to higher gas prices or fuel switching. *Id.* at pp.70-71. Even so, his proposed solution of removing the throughput incentive is broad enough, in his opinion, to protect PNM from all such risks.

“I said those words are not in the Act, but my reading of the removing of disincentives supports the fact that the throughput incentive, which is the utility’s ability to earn more or generate more revenues as volumes increase, is something that needs

to be removed before a utility can go forward aggressively with energy efficiency and conservation programs. **So to me that throughput incentive embodies all factors related to use per customer.**" *Id.* at p.69. (emphasis supplied). Mr. Feingold's focus is on use per customer, and his decoupling proposal "Rate Rider 16 is premised on use per customer." *Id.* at p.85. His premise finds no support in the EUE.

This single-minded focus on use per customer ignores PNM's overall economic picture and has negative consequences for customers. The EUE requires that a utility be made financially neutral. PNM's decoupling proposal is designed to be a financial windfall¹⁸ instead.

Mr. Feingold defines "margin revenues" as "the non-gas cost-of-service for the utility that is approved in the last rate case." *Id.* at p.86. He uses the term to mean the total non-gas revenue requirement approved in the last rate case. *Id.* at p.197. His RR 16 "only uses the customers approved in ... the Company's last rate case." *Id.* at p.88. PNM's decoupling proposal does not take into account revenue contributions of new customers. *Id.* at p.126. Mr. Feingold agreed that use per customer can decline but PNM can still recover its margin revenue. *Id.* at p.129. This decline in use per customer triggers an upward adjustment (an increased charge) even when new customers exactly make up for reduced total use by old customers, so that the throughput, or volume of gas PNM sells, is the same. *Id.* at pp.122-125. In other words, under PNM's decoupling proposal, when PNM sells precisely the same amount of gas because of customer growth and there is no reduction in throughput or revenues,

¹⁸ "I think ... that although the adjustments to any one customer is not large relative to the customer's overall bill, when you add up all of those adjustments for the customers that the company serves, that ... can have a material impact on the ability for the company to recover the revenues approved by the Commission." Tr. 12/14/06, p.80.

according to PNM witness Feingold, the “decline in use per customer when compared to the rate case number generates the need for an upward adjustment [increase] to compensate the company for that loss in revenue.” *Id.* at pp.124-125. But there is no loss in revenues, just a decrease in revenue per customer.

Under the decoupling proposal PNM will be “compensated” for lost revenues even when revenues do not go down. They will also be compensated, under Mr. Feingold’s decoupling proposal, when use per customer declines, but total revenues are higher than those approved in the previous rate case. Under this scenario, customers will still be assessed a surcharge. *Id.* at p.160.

The only way to receive a credit is if per customer use increases, as can happen during very cold weather. PNM points to the resulting stabilizing effect on bills, which would be lower during cold winters and higher during mild winters, as a benefit to customers. This benefit would, over the last five years, have come with a price. The cost to PNM’s customers would have been over \$16 million. Moreover, PNM’s customers have significantly reduced per customer gas use in recent years, primarily in response to higher natural gas prices. The effectiveness of the price signal and of the customer conservation response would be reduced by decoupling.

PNM will be compensated for “losses” that do not occur, and even when the “losses” per customer are accompanied by an increase in total revenue, PNM will be compensated for these losses, too. And all of this is accomplished with decoupling’s simple true-up mechanism. Mr. Feingold describes all of this as necessary: “we have to move towards a new ratemaking paradigm....” *Id.* at p.157. Other regulatory

innovations¹⁹ have been labeled in a similar way. The results, particularly for electric restructuring, have been much higher rather than lower rates: "... Pennsylvania is not the only place where there has been some disappointment." Tr. 12/14/06, p.184. In the field of utility regulation, new paradigms have proven very expensive in the last ten years. Fortunately, the New Mexico Legislature prevented New Mexico from suffering the major electric rate increases experienced by the many states that accepted the arguments that electric deregulation would lower rates. Tr. 12/14/06, pp.184-187, 238

In recent years PNM's total throughput (volumes of gas sold and delivered) has increased due to customer growth even while the use per customer has declined. *Id.* at p.179. If decoupling had been in place during the years 2001-2005, PNM would have received an additional \$16.5 million from its natural gas customers, an average of \$3.3 million a year. Tr. 12/14/06, p.91. In that time frame, it did not have significant energy efficiency programs in place.

¹⁹ In its Order approving Formation of a Holding Company issued on June 28, 2001 in Case No. 3137 (pp.2-3) (emphasis supplied), the Commission authorized PNM to form PNM Resources ("PNMR") and recognized New Mexico's good fortune to still be among the states with traditional utility regulation.

"The Restructuring Act originally called for competition in the New Mexico retail electricity market to begin earlier this year on January 1, 2001, for residential, small business customers, and public schools and colleges, with large business starting one year later. NMSA 1978, Section 62-3A-4(A) (1999). The Legislature gave the Commission authority to delay customer choice and other dates in the Restructuring Act by up to one year. The Commission did so in an Order issued in May of 2000. But for that delay, New Mexico residents, schools and small businesses would have been at the mercy of the prevailing wholesale price for electricity for the last six months. They would no longer have been entitled under New Mexico law to electricity at just and reasonable rates."

"Because the Legislature gave the Commission authority to delay competition, New Mexicans will spend several hundred million dollars less just this year for their electricity. As New Mexico State University Professors Dr. Douglass Gegax and Dr. Paul Turner concluded in September of 2000 at a Commission Work Session on Recent Market Conditions Affecting Electricity Restructuring: 'It is interesting to note that the current regulated price path looks pretty good for New Mexico consumers.' California Electricity Markets: Lessons Learned for New Mexico, September 26, 2000, p.26."

PNM's recently established gas energy efficiency program has 934 participants out of about 470,000 natural gas residential gas customers. AG Brief in Chief, p.14. The AG also points out that PNM's gas energy efficiency program investments are funded "by a customer surcharge through a rate rider...." AG Reply Brief, p.6.

Staff witness Sisneros testified in favor of decoupling and about the complexity of determining the exact amount of lost revenues PNM would experience because of company efficiency programs. Staff Exhibit 5 (Sisneros Direct), pp.10-11. At the hearing he agreed that Staff and the parties are capable of dealing with those problems if "given adequate time and resources it's possible." Tr. 12/20/06, p.112.

The AG stressed that at hearing PNM admitted RR 16 as proposed is "flawed in that additional throughput per customer did indeed result in increased margin and thus a significant incentive to increased throughput. (Transcript, Dec. 19, p.114....)" AG Reply Brief, p.9. PNM admitted this flaw and offered to correct it. PNM Brief in Chief, p.102. "...the description would be corrected ... with that clarification, the CNA [decoupling] will eliminate the throughput incentive for PNM ... the CNA provides significant benefits to customers and the Company."

The Commission agrees that the record shows benefits of decoupling for PNM, but does not agree that it would benefit customers. PNM's proposal is inconsistent with and oversteps the EUE. It would not, as required, make PNM "financially neutral" relative to resource choices. It would, instead, give PNM insulation from a large variety of business risks including the risk of customer response to higher prices. PNM properly bears those risks. PNM's presentation on this issue is unpersuasive. PNM fails to meet its burden of proof.

The EUE requires the Commission to “identify any disincentives or barriers that may exist for public utility expenditures on energy efficiency and load management, and, if found, ensure that they are eliminated....” NMSA 1978, Section 62-17-5(F) (2005). The Act does not require approval of PNM’s proposal to insulate it from the vast majority of its business risks and provide it with an “enhanced opportunity to recover its Commission-approved revenue requirement.” Brief in Chief, p.104 (emphasis supplied). PNM is correct that it has an opportunity; but the legal standard is that it be a fair one, not one enhanced by an ill-advised decoupling mechanism.

The record shows that the two rate classes, small commercial and residential, that would be affected by decoupling provide PNM with almost 94 percent of its margin revenues and are about 98 percent of the total number of PNM customers. Tr. 12/14/06, p.217. A result of approving decoupling would be that at least 93 percent of PNM’s total revenues would be assured of recovery. *Id.* at 218. This would put PNM in a position of having a significantly reduced overall business risk. Consistent with that position, Staff and other parties contend that PNM would then be entitled to a lower return on equity.

PNM takes a decidedly different view. PNM witness Hadaway asserts that if decoupling and a higher winter customer charge of \$15.00 a month (instead of the present charge of \$9.00 and PNM’s proposed \$11.00 charge) “were not being proposed by PNM, it would be appropriate to increase PNM’s requested ROE to account for its more risky position.” PNM Exhibit 18 (Hadaway Direct), p.28. He relies on the fact that his “peer group” of comparable gas utilities have decoupling. His testimony is that 5 of 10 do. Tr. 12/18/06, p.96. Which means 5 of 10 do not.

Dr. Hadaway's selection of a peer group²⁰ of this 50/50 composition may or may not reflect the overall industry average. *Id.* at p.97. In any event, PNM has not met its burden of proof in this case concerning decoupling. PNM, if it had decoupling, would have substantially reduced risk and very little uncertainty regarding its revenues. Under Bluefield, this situation would necessarily result in a lower rate of return than what we have determined is fair in this case. The Commission does not agree with PNM that it is entitled to a higher rate of return than what is authorized in this case.

If any other states are significantly reducing a utility's risk with a decoupling plan having the same features as PNM's proposal without reflecting the corresponding reduction in risk and revenue uncertainty in the authorized rate of return, we are not obligated to follow any such departure from established principles. Any such departure from the Bluefield standards raises significant issues.

PNM's proposal for decoupling and its related proposal for an increased rate of return in the absence of decoupling do not comport with the fundamental nature of utility regulation. The primary result that would flow from decoupling would be to insulate PNM's revenues from customer response to the higher prices for natural gas experienced in recent years. PNM's request to be so insulated surpasses the proper limits of utility regulation. As the United States Supreme Court explained in Market St. Ry. Co. v. Railroad Commission, 324 U.S. 548, 568 (1945). "Even monopolies must

²⁰ In future rate cases, care should be taken by PNM, Staff and others to ensure that comparable utilities are as similar to the New Mexico utility as possible. The burden will be on the proponent of a comparable group of utilities to document by a written determination by the relevant state commission of the level of any utility's revenues that are assured of recovery if the proponent asserts that the level of risk for the New Mexico utility in the subject rate case is somehow different compared to one or more members of the comparable group.

sell their services in a market where there is competition for the consumer's dollar and the price of a commodity affects its demand and use."

PNM is authorized a return on equity above a risk free rate. One of its business risks is that customers will use less natural gas, per customer, in response to higher natural gas commodity prices. The record in this case shows that despite this per customer decline, PNM's overall sales have increased²¹ because of customer growth.

PNM's decoupling proposal would protect it from a wide range of business risks. And PNM wants this protection without any reduction in its authorized return on equity, despite the clear reduction in risk attendant to PNM's proposal. In declining PNM's proposals, we are mindful that an aspect of symmetry is required in utility regulation. The United States Supreme Court made it clear that a utility is entitled to consistent, symmetrical treatment. "Consequently, a State's decision to arbitrarily switch back and forth between methodologies in a way which required investors to bear the risk of bad investments at some times while denying them the benefit of good investments at others would raise serious constitutional questions." Duquesne Light Co. v. Barasch, 488 U.S. 299, 315 (1989). Accepting either of PNM's proposals would raise a serious issue concerning that required symmetry.

Although PNM has offered to "fix" the flaw in RR 16, the shortcomings of RR 16 are not amenable to any fix. It goes beyond what the EUE authorizes or requires and it suffers from other shortcomings as well.

²¹ Since early 2003, the average residential cost-of-service component of a bill is now 2.8 percent lower, but over the same timeframe PNM has added 30,000 new customers, an increase of between 6 and 7 percent. Tr. 12/13/06, pp.79, 85.

The parties identified additional problems with PNM's decoupling proposal. They argue it violates the requirement of NMSA 1978, Section 62-8-7(E) that there be a hearing before there is a change in rates, except in the case of several specific cost factors. PNM argues the EUE creates an exception to this hearing requirement. PNM's position is incorrect. A change in sales volumes is not one of the identified exceptions.

PNM's request is contrary to the well-settled doctrine that "where a statute explicitly enumerates certain exceptions to a general grant of power, courts should be reluctant to imply additional exceptions in the absence of a clear legislative intent to the contrary." U.S. v. NEC Corp., 931 F.2d 1493, 1502 (11th Cir. 1991); Davis v. Davis, 911 F.2d 560, 562 (11th Cir. 1990) (courts "are not free to create by interpretation an exception in a statute which is plain on its face"); Cottonwood Mall Shop. Ctr., Inc. v. Utah Power & Light Co., 440 F.2d 36, 40 (10th Cir. 1971), cert. denied, 404 U.S. 857 (1971) (State public utility statutes "must be given a liberal reading to provisions subjecting the activity to regulation while simultaneously giving a more narrow scope to the exceptions"); see also, State v. Board of County Commissioners, 62 N.M. 137, 140-141, 306 P.2d 259 (1957) (anyone claiming the benefit of an exemption must clearly and unmistakably establish his right to it).

Section 62-8-7(E) provides as follows. "Except as otherwise provided by law, any increase in rates or charges for the utility commodity based upon cost factors other than taxes or cost of fuel, gas or purchased power ... shall be permitted only after notice and hearing...." PNM argued it is not changing cost factors so Section 62-8-7(E) does not apply. The AG responds that PNM wants decoupling to recover its costs, and that to "be just and reasonable, rates must be cost-based." Reply Brief, p.10. We agree

with the AG and note that PNM would increase its delivery (transmission and distribution) rate under RR 16 based on the reduction in the amount of gas a customer uses.

The parties also contend that decoupling would discourage ongoing customer-initiated conservation efforts. In effect, under decoupling customers could no longer reduce what they pay to PNM for transmission and distribution. They would only save on the commodity portion of their bill. PNM's reaction is to dismiss as relatively small the additional costs decoupling would impose on customers who voluntarily reduce their own use of natural gas. A PNM customer who conserves on their own will not have the savings associated with a reduction in throughput and Mr. Feingold considers that amount minimal. Tr. 12/14/06, p.235. Earlier, he expressed his opinion on the present treatment afforded PNM's natural gas customers who conserve. "Quite frankly, the way the rates are designed currently, I believe that customers are overpaid to the extent that they reduce their energy consumption by virtue of the fact that they are saving on fixed costs through the variable portion of the rate where that shouldn't be happening." *Id.* at p.231.

The Commission does not agree that customers who conserve are "overpaid" under the present rate design. The record shows that PNM's customers would have paid an extra \$16.5 million between 2001 and 2005 had decoupling, as proposed by PNM, been in place. We consider this evidence sufficient to conclude that decoupling would discourage conservation efforts. PNM's proposal is inconsistent with the EUE.

Additional issues such as whether decoupling is inconsistent with regulatory lag or whether it would constitute retroactive ratemaking may have merit but need not be

decided in this case. The Commission finds that decoupling is not in the public interest and is inconsistent with the Public Utility Act.

The EUE requires the Commission to make certain determinations. They apply not just to PNM's natural gas service, but to all natural gas and electric utilities in New Mexico. We will make the necessary determinations in a separate case, one devoted exclusively to those issues. The other affected electric and natural gas utilities will be able to fully participate in that case. The testimony and argument provided in this case, and the Commission's decisions, serve to inform and guide Utility Division Staff and potential parties to that later case of certain issues to be considered and what approaches have already been considered and rejected.

Finally, we note that PNM in its Brief in Chief (p.6) identifies nine states that have decoupling for natural gas utilities, several of which are using a three-year pilot program. PNM suggests a three-year pilot program for New Mexico as an alternative to its proposal. We do not know the details of the decoupling plans in use in those nine states (or how many of the remaining 40 states have rejected a decoupling proposal), but the record in this case conclusively demonstrates that a pilot program is not needed in New Mexico because PNM's decoupling proposal is fatally flawed.

3. Conservation Adjustment

PNM requests that if decoupling is denied, the Commission grant it an annual increase to test period revenues of \$2,855,503. The basis for PNM's request is that it wants the increase in revenue requirement to "reflect the impact of a significant decline in per customer usage during the winter of 2005/2006 PNM believes that the reduction in usage was a direct result of higher natural gas prices and PNM's efforts to

effectively communicate those price signals to PNM's customers." PNM Brief in Chief, p.114. PNM asks to incorporate the difference between January through March per customer gas use in 2006 as opposed to the gas use per customer for same months in 2005. PNM explains that the "adjustment is being sought because the test year, twelve months ended December 31, 2005, does not reflect the full impact of the reduced consumption." Id. PNM argues that its request qualifies as a known and measurable change. Id. at p.115. NNSA argues against PNM's request. NNSA Reply Brief, pp.42-47.

Attorney General witness Roybal testified against PNM's request.

This adjustment considers data outside the test-year. This recommendation is not recognized in any of PNM's filed schedules included in this case. This request basically updates one critical element of a rate proceeding, to the benefit of PNM, without updating all other data through March 2006. Furthermore, an adjustment of this magnitude, 14% of the total increase requested, will have a significant impact on rates. This raises an issue with proper notice of the rate filing. I recommend the Commission deny this request on the basis that it is outside the test-year. In the alternative, I recommend the Commission stay this proceeding and require PNM to file a new rate case with a 12-month test-year ending March 2006. This will synchronize PNM's request with the appropriate test-year.

AG Exhibit 3 (Roybal Direct), pp.29-30.

The Commission shares Mr. Roybal's concerns. The selection of the 12-month period ending December 31, 2005 for a test year was a matter entirely within PNM's control. Had PNM chosen a test year starting three months later and ending on March 31, 2006, all of the information concerning PNM's revenues (whether increases or decreases) as well as its costs would be properly before the Commission. Moreover,

PNM's sales volumes for the first three months of 2006 would have been known to PNM before it filed this case at the end of May in 2006. The Commission concludes that PNM's conservation adjustment request does not qualify as a known and measurable change and should be denied.

4. Load Growth Adjustment

As part of its rate design, PNM adjusted its base period revenues to account for its forecasted customer growth. PNM used the difference between its number of residential and commercial customers at the end of 2004 and 2005 to project its customer growth rate for 2006. PNM calculated "an adjustment of \$1,338,341 in additional revenues projected from the growth in number of customers." PNM Brief in Chief, p.115. This projected increase reduces PNM's revenue requirement, consistent with past Commission practice.

NNSA objected to PNM's adjustment. NNSA Brief in Chief, pp.50-52; NNSA Reply Brief, pp.47-48. NNSA's approach would "result in an additional Test Period revenue of \$740,766 (Kumar Direct), NNSA Exhibit 1, Schedule 40)." NNSA Brief in Chief, p.51.

According to PNM, Mr. Kumar's growth adjustment was based on a customer count number at mid-2006 levels, some six months after the end of the test period. NNSA contends that PNM should have used year-end average growth rates (2.32% for residential and 1.30% for commercial) rather than half of those figures (1.16% for residential and 0.65% for commercial). NNSA Brief in Chief, p.51.

The initial appeal of NNSA's position evaporates quickly. The purpose of PNM's adjustment is to estimate future revenues based on the average number of customers in

the year following the test period. Customer growth takes place over the course of a year. Using the projected number of customers at the end of the next year, in other words using the full year growth projection of 2.32%, shows how many new customers there are at the end of the next year. But there are not that many new customers at the end of one, two, six or even ten months.

PNM's use of one half of the total year growth rate reasonably reflects the average number of new customers over the course of the next year. PNM's position on this issue is accepted.

5. Load Factor Adjustment

As part of its method used to compute the peak demand for both coincident and non-coincident peak for each customer class, PNM conducted an automated meter reading study for each class customer. PNM Exhibit 25, (Fernald Direct), p.16. The study uses daily meter readings where available to establish daily peaks and uses a load factor adjustment where daily meter reads are not available. The load factor adjustment is computed using automated meter reading data for a sample of residential and small commercial customers. According to PNM, this method uses additional information to more accurately determine the proper peak day demand used in designing rates. PNM Brief in Chief, p.117.

NNSA opposed the use of the load factor adjustment proposed by PNM, because PNM did not adjust the load factors for all classes. By not using all classes, NNSA claims PNM penalizes some customer classes by increasing their peak loads and thus allocating higher costs and expenses to these classes. NNSA Exhibit 1 (Kumar Direct), p.74.

PNM agrees that not all classes were used to calculate a load factor adjustment and points out that those classes were customer classes that had no daily meter reads. PNM states that those rates include Rate No. 30 (Irrigation), Rate No. 31 (Water and Sewage Pumping), Rate No. 35 (Cogeneration Service) and Rate No. 37 (Gas Air Conditioning), and they collectively represent only 6/10ths of one percent of the cost-of-service revenues. PNM Exhibit 25, (Fernald Direct), p.18. PNM concludes that even if there were daily reads or if a proxy estimate were made, the results would be insignificant in terms of determining peak day demand for other customers. *Id.* The Commission agrees with PNM's conclusion and rejects NNSA's position.

6. Lost and Unaccounted-For Gas- Transmission vs. Distribution

PNM did not adjust its peak load demand data to account for the lower losses and unaccounted-for volumes of gas experienced by its transmission system than by its distribution system. PNM Exhibit 26 (Fernald Rebuttal), p.14. PNM contends that the consequences to customers of trying to measure the difference in terms of computing peak-day usage is insignificant compared to the benefit transmission customers already enjoy of not having a distribution charge. PNM Brief in Chief, p.118. NNSA objects to PNM's non-adjustment reflecting a different lost and unaccounted for gas factor for transmission and distribution lines. Mr. Kumar contends that such failure allocates more cost to customers taking service from PNM's transmission system. NNSA Exhibit 1 (Kumar Direct), p.74.

PNM noted that although Mr. Kumar states that the failure to make such an adjustment due to different percentages of lost and unaccounted for gas is unfair, he fails to quantify the dollar impact upon transmission customers. PNM's non-discounted

transmission rate is approximately half of the rate that would be paid for both transmission and distribution. PNM Brief in Chief, p.118. PNM argues that while there may be a one or two percent difference in the lost and unaccounted for gas, the savings already achieved by transmission customers, who only pay for transmission service and not distribution, is much greater. PNM concludes the adjustment is not necessary in order to make the rates fair to both transmission and distribution customers. To provide the exact lost gas factor to reach individual bills would require extensive additional metering and modification to the billing system and, according to PNM, these costs would exceed any benefit. *Id.* The Commission accepts PNM's position on this issue.

7. Cost-of-Service Study Issues/Customer Charge

An allocated cost-of-service study is a tool designed to distribute the revenues, expenses and rate base of a utility among its customer classes. Its purpose is to determine the relative rates of return for the classes. Revenues, expenses and rate base are directly assigned or allocated through the study to the various customer classes.

In order to allocate the various items, factors are developed which reflect the causal relationship with the incurring of an expense or investment. The end result of the study are class rates of return which are used, along with judgment and public policy criteria, in the actual distribution of a rate increase or decrease among customer classes.

There are three basic steps in an allocated cost-of-service study. The first step is "functionalization" in which investments and expenses are separated into the main functions performed by the utility. The second step is "classification" where the

functional investments and expenses are divided into demand, commodity or customer components. The final step is "allocation." After the direct assignments are identified, the balance of investments and expenses are allocated to customer classes using allocation factors designed to reflect a causal relationship between the cost and the class responsible for the cost.

Staff witness Brack explained the next step in the process, which is how utility rates are designed.

Rates are designed to the extent practical, so that each rate class contributes sufficient revenue to cover the cost of serving that rate class, including a return on rate base. Rates designed in this manner would result in each end-use class's rate of return being equal. Each end-use class would have a relative rate of return being equal to 1.0. This is referred to as a unity rate of return and is when the relative rate of return for any one class is equal to the return of all classes as a whole. A goal of rate design is for each customer class to be responsible for its fair share of the cost-of-service and the elimination of cross subsidies between classes. Because of rate shock potential which may arise from moving to a unity rate of return, gradualism is a common and acceptable practice.

Staff Exhibit 6 (Brack Direct), pp.2-3.

Mr. Brack then explained why Staff used a pro rata allocation of any rate increase, rather than using the full cost-of-service resulting from the class cost-of-service study.

Allocating rate changes based upon a fully allocated class cost-of-service study is generally the most common starting point in developing class revenue requirements and rate design. Direct application of class cost-of-service study results, however, is seldom (if ever) fully utilized. Instead, analysts and the Commission generally apply some sort of limitation to the amount of increases or decrease allowed in the revenue requirement for each class in order to avoid too

radical an alteration of rates. Given the minor impact a traditional class cost-of-service study would have and the relatively small revenue increase recommended in this case by Staff, Staff believes the assignment of the proposed rate increase on a pro rata basis to each class is a fair approach The pro rata allocation of Staff's adjustment to rate schedules was made in the same percentages as PNMGS' revenue increase ... to the various rate schedules.

Id. at pp.5-6. UNM opposes Staff's pro rata approach and prefers "setting PNM's gas service rates at levels that gradually move each end-user class closer to full recovery of its COSS-calculated cost-of-service." UNM Response Brief, p.35, UNM Brief in Chief, pp.44-49. But Staff used a pro-rata calculation only for "comparison purposes" before PNM's final run of its rate design after the recommended decision is issued. Staff Exhibit 6 (Brack Direct), p.5.

Staff supports PNM's fully allocated cost-of-service study and rate design. Staff witness Brack concluded that PNM's "rate design methodology will result in rates that are equitable and will result in the efficient collection of [PNM's] required revenue. Staff is satisfied with the efficiency of PNMGS' ... methodology and recommended it be adopted in the ultimate rate design in this case." Id. at pp.3-4.

NNSA asks the Commission to further unbundled non-PGAC cost-of-service rates and require PNM "to exclude all gas service related costs from the transportation service charges and charge these costs as part of non-PGAC gas supply rates to the sales customers only." NNSA Brief in Chief, p.6. The Commission rejects this request.

As the Commission previously explained:

Staff and the AG contend that it is proper to combine sales and transportation customers for cost allocation purposes within each class since sales and transportation customers have similar load characteristics, interruption priorities and

similar costs of service for customer-related matters. The Commission agrees with this analysis and notes that under GCNM's filing in this case, a customer of GCNM, regardless of the class involved, can receive sales and transportation service through the same meter.

Recommended Decision, Case No. 2147, p.88.

Consistent with Case No. 2147 and other Commission Orders in prior cases, PNM combines the retail sales customer and the on-system discounted transportation end-users for allocation purposes. Since retail customers and transportation end-users can and do switch between these like services, there is no difference in the impact to PNM's cost-of-service whether a customer is a retail customer or a transportation end-user. PNM Exhibit 25 (Fernald Direct), p.6. As was done in past cases, PNM tailored its fully-allocated cost-of-service so that there was a gradual move of each end-use class to a relative rate of return closer to unity. NNSA agrees with these allocation principles, but disagrees with some aspects of the cost-of-service study.

The AG and NNSA disagree with different aspects of PNM's rate design. The AG objected to PNM's proposal concerning the appropriate access fee (or customer charge) for residential service. AG witness Ruback objected to PNM's use of a minimum distribution main and recommended that distribution mains should be classified as a 100% demand with no customer component. AG Exhibit 2 (Ruback Direct), p.13. In the alternative, if a customer component in distribution mains is recognized, he recommended that the customer component be calculated using a zero intercept method instead of the minimum size used in PNM's cost-of-service study. *Id.* at p.18.

NNSA was critical of PNM's access charge assessed to non-residential customers, arguing that those monthly access fees are substantially less than PNM's calculated cost-of-service for those classes. Mr. Kumar recommended that the access fee for each customer class be equal to 50% of the class' customer-related cost-of-service. NNSA Exhibit 1 (Kumar Direct), p.80; NNSA Brief in Chief, pp.100-104. He also indicated that PNM should only be able to charge one monthly access fee per customer even if the customer had multiple meters. *Id.* at p.81. None of these positions are persuasive.

PNM points out that the arguments of both the AG and NNSA are not new. These arguments have been made in prior cases and have been rejected by prior Commission Orders. PNM Brief in Chief, p.120. In Case No. 2662, Mr. Ruback made the same argument concerning the minimum two-inch distribution system approach proposed by PNM. Mr. Ruback's proposal was rejected by both the Hearing Examiner and the Commission in Case No. 2662. UNM and NNSA oppose the AG's position. In 1988, the AG objected to the two-inch minimum distribution system in PNM Case No. 2147. The Recommended Decision concluded the following:

The AG criticized use of GCNM's minimum system which is based on two-inch diameter distribution mains. AG witness Oliver argued that the minimum size used by GCNM is not necessary for smaller customers so their costs are overstated. However, GCNM's method is widely accepted and the total system needs must be taken into account. The Commission agrees with GCNM's minimum system based on two-inch distribution mains.

Recommended Decision, Case No. 2147, p.92 (citations omitted). The Commission reaches the same result in this case.

There is a wide range of recommendations for a monthly customer charge or access fee for residential customers. PNM asks that the present fee of \$9.00 be increased to \$11.00. The AG argues that it should be decreased to \$7.00. AG Brief in Chief, pp.15-17. Under NNSA's proposal it would decrease to \$8.50. Another option is leaving it at its present level of \$9.00. And Staff testified in favor increasing the customer charge to \$10.26. Staff Exhibit 6 (Brack Direct), p.7. After considering the arguments of the parties and the record, the Commission concludes the monthly residential customer charge will be Staff's figure of \$10.26. The Commission accepts the PNM rate design, which is supported by Staff.

IV. Miscellaneous Issues

1. Elimination of Discounted Transportation Rate for Electric Generation

PNM offers discounted transportation rates to a variety of customers. Staff witness Schwebke explained that PNM's gas utility "provides discounts on system transportation service to several customers, including PNM electric generating stations. The revenue brought in from these customers for the discounted service totals \$2,114,210, and is treated as a revenue credit against the total cost-of-service for the sales customers." Staff Exhibit 2 (Schwebke Direct), p.8. The annual revenue credit to sales customers (such as residential and small commercial customers) resulting from the discount to PNM's electric generating stations is \$70,000 to \$75,000, according to PNM. Tr. 12/13/06, p.103.

Mr. Schwebke explained his proposal to eliminate the discount for gas transportation to PNM's electric generating stations.

When PNM electric generation makes use of the PNM gas discounted transportation rate, it is for the purpose of generating power for the sale on the open market. It is true that PNM gas customers benefit from the revenue credit. However, large quantities of gas offered at a discount rate, are burned to generate electricity for the profit of PNM corporate. At the same time, PNM Gas is authorized to pass through the cost of various energy efficiency programs to residential customers where the projected gas conservation is minimal. It would appear that real energy savings could be realized if PNM gas simply dropped its discounted transportation rate to PNM electric generating stations. It is true that if the Commission so ordered in this case, it would be proper to remove the associated revenue credit against the cost-of-service. It would however, appear to result in some real measurable energy savings.

Staff Exhibit 2 (Schwebke Direct), p.9.

Staff witness Schwebke, the Chief Staff Engineer for natural gas and water, explained his concern at the hearing. "I just find it contradictory ... that PNM would continue to offer discounted rates for electricity generation that would provide the same amount of energy savings in a very short period of time that their energy conservation program is providing in a year, ... within 80 hours of generation from one plant." Tr. 12/20/06, p.17. Despite this legitimate concern, the Commission concludes it will not grant this request. The forces at play in the decision of what fuel to use to generate electricity are much larger than the \$75,000 discount involved.

There was testimony at the hearing that there is a tight balance between supply and demand for natural gas. Tr. 12/13/06, p.83. A number of witnesses observed that aggregate national demand, of which demand in New Mexico is a very small part, determines the market price for natural gas. The commodity price of natural gas has increased by a factor of more than three over the last 10-12 years. Over this same

period, Mr. Schwebke testified, "the largest sector of growth in the natural gas usage has been for electricity generation." Tr. 12/20/06, pp.25-26. This period of increased reliance on natural gas to generate electricity prompted the following observation from Staff witness Schwebke. "Sort of corresponds with the rise in prices in the natural gas market." *Id.* at p.26.

The purpose of this natural gas rate case is to set just and reasonable rates for the services provided by PNM's natural gas utility. The majority of a customer's bill is not for those services, but for the natural gas PNM resells at no markup. The market price of natural gas is, however, to some degree influenced by the decisions of this and other state utility commissions. An over-reliance on natural gas to generate electricity began amid a period of low prices. The fact that the low prices ended was in no small part due to the decisions made across the country to rely on natural gas for most new electric plants. These decisions overlooked the long-term value of fuel diversity.²²

They have also come at a considerable cost. The natural gas used to generate electricity has for years not been the bargain it was in 1995. More importantly, the increased demand for natural gas due to the nation's heavy reliance on it to generate electricity contributed to the increased price of natural gas used for all purposes, including home heating. The extent to which the increased price resulted from using so much natural gas to generate electricity is the proper subject of academic inquiry.

²² This Commission long ago recognized the importance and value of fuel diversity for an electric utility. *Re Public Service Company of New Mexico*, 101 P.U.R. 4th 126 (NMPSC 1989) (Case No. 2146 II), *aff'd sub nom.*, *New Mexico Industrial Energy Consumers v. New Mexico Public Service Commission*, 111 N.M. 622, 808 P.2d 592 (1991). Remembering that recognition is equally important.

Learning the right lessons depends on posing the right questions. Mr. Schwebke's testimony contributes to this process.

2. Late Charge

CANM asks the Commission to eliminate PNM's late payment charge of 1.5% a month on accounts over 30 days past due. Alternatively, CANM asks the Commission to lower the 18% annual rate to no more than 13% and further limit its application so it would apply only to accounts past due 60 days, with at least a balance of \$200 and exempt low-income customers and those whose accounts are not subject to collection for regulatory reasons. CANM Brief in Chief, pp.1-2, 6-15; Reply Brief, p.6.

PNM responds that without "a late payment charge, a customer would have no incentive to pay the utility bill ... as opposed to other bills with a late charge. PNM would then be faced with costs related to collections and disconnections." PNM Brief in Chief, p.122. PNM relies on the stipulation in Case No. 2307 where the parties agreed the late payment charge would no longer be experimental. That stipulation was approved by the Commission's Final Order in that case.

CANM correctly points out that the stipulation was approved by the Commission, but with the express provision that no part of the stipulation would be of precedential value. The Commission views its Final Order in Case No. 2307 as approving the existence of the late charge. That approval did not, as PNM concludes, "remove[d] PNM's obligations from the prior case to provide any further information regarding the issue raised in Case No. 2147." PNM Brief in Chief, p.123.

The burden of proof still resides with PNM to justify the amount of its late charge. PNM relies on its need "to compete with credit card companies charging interest rates

of 1.5% [per month] on the unpaid balance.” *Id.* at p.124. CANM demonstrated credit card interest rates reported by the Federal Reserve Board on December 7, 2006 “indicated that the PNM late fee should now be reduced to no more than 13%.” CANM Brief in Chief, p.14. The Commission agrees with CANM and PNM’s late charge will be reduced to 13% per year. CANM’s other requests concerning the late charge are not accepted.

3. Winter Moratorium

CANM contends that in the winter of 2005-2006 PNM violated the winter shutoff moratorium statute. NMSA 1978, Section 27-6-18. CANM Brief in Chief, pp.1-5, 14-40; Reply Brief, pp.1-5, 7-11. The alleged violations include the failure to provide pre-termination notice of winter shutoff moratorium protections, false and deceptive threats of disconnection and improper imposition of additional fees.

Both PNM and CANM provided extensive briefing on the issues raised. The intricacy and serious nature of the issues deserve and have received careful consideration. The ultimate conclusion reached is that all of the winter moratorium related issues are outside the scope of this rate case. Fairness to both PNM and CANM requires that these issues not be decided in this rate case. This decision is made without prejudice to any position taken on these issues by PNM or CANM. Both parties are to be commended for thoughtful presentations on these issues. The Commission makes no ruling concerning the merits of any issue involved. The Commission’s treatment of these issues should in no way be interpreted to preclude CANM from pursuing these issues by filing a complaint case at the Commission, or by other legal process.

V. Revenue Requirement

The attached exhibits and schedules show the rate base, cost-of-service, revenue requirement, rate design and proof of revenue for PNM that result from the decisions described in this recommended decision. More specifically, Exhibit A shows the Hearing Examiner's proposed cost-of-service on pages 1-8. The recommended rate base of \$390,854,304 represents a reduction of \$18,376,975 from PNM's requested rate base of \$409,231,280. Exhibit A, p.2. The recommended revenue requirement of \$151,667,247 is a reduction of \$9,821,179 from PNM's requested revenue requirement of \$161,488,426. This recommended revenue requirement of \$151,667,247 shows that compared to the base year cost-of-service revenues of \$140,183,096 there is a revenue deficiency (or recommended rate increase) of \$11,484,151. Exhibit A, p.8; Schedule A-1. In short, PNM would receive a rate increase of \$11,484,151 rather than its requested rate increase of \$21,305,330.

Schedule A-1 is a Summary of the Overall Cost-of-Service and PNM's Claimed Revenue Deficiency. Schedule A-2 is a Summary of Cost-of-Service Adjustments by Functional Classification. Schedule A-3 is a Summary of Rate Base. Exhibit B shows the revenue distribution over the different rate classes of the recommended rate increase. Exhibit C is a Revenue Analysis which shows rate changes by customer rate class and Exhibit D is a Proof of Revenue.

VI. Findings, Conclusions and Decretal Paragraphs

The Hearing Examiner recommends that the Commission **FIND** and **CONCLUDE** as follows:

1. The Statement of the Case, the Discussion, and all findings and conclusions contained therein, whether or not numbered or designated as such, are incorporated herein as findings of fact and conclusions of law.

2. PNM is a public utility as defined by NMSA 1978, Section 62-3-3(G) and is subject to the jurisdiction of the Commission pursuant to the Public Utility Act, NMSA 1978, Section 62-3-1 *et seq.*

3. The Commission has jurisdiction over the parties to this case and the subject matter thereof.

4. Reasonable, proper and adequate notice of this case has been given.

5. PNM's present rates are not fair, just and reasonable.

6. The tariffs filed under Advice Notice Nos. 755 and 756 contain rates which are not fair, just and reasonable.

7. Cost-of-Service Exhibit A, Rate Design Exhibit B, Schedules A-1, A-2, A-3, Revenue Analysis Exhibit C and Proof of Revenue Exhibit D appended hereto are incorporated by reference. The rates therein are fair, just and reasonable.

8. PNM should implement new rates based on a Base Period ended December 31, 2005.

9. The rates of PNM are inadequate and should be increased by \$11,484,151 as reflected on Cost-of-Service Exhibit A and Schedule A-1.

10. PNM should file, under new Advice Notices, new rates and rules consistent with the cost-of-service determination reflected in this Order and in Cost-of-Service Exhibit A and the other Schedules and Exhibits. Such rates shall be effective upon approval as to form and compliance by Commission Staff. PNM should be

required to implement such rates for service rendered on and after the compliance approval.

11. PNM's Rate Rider 16 (decoupling proposal) and Rule No. 38 should be rejected with prejudice.

12. PNM should be granted approval to abandon its San Ysidro gas storage facility.

13. Unless specifically ruled on, all matters are disposed of consistent with this Order.

The Hearing Examiner recommends that the Commission **O R D E R** as follows:

A. The findings, conclusions, decisions, rulings and determinations made and contained herein are ordered to be carried out and complied with.

B. PNM's rates filed pursuant to Advice Notice Nos. 755 and 756 are hereby disapproved.

C. PNM shall file new rates and rules consistent with this Order and with the rules and regulations of the Commission. They will be effective for service following their approval as to form and content by Staff.

D. Rate Rider 16 and Original Rule No. 38, PNM's decoupling proposal, are disapproved on the merits.

E. PNM is granted all authorizations necessary under NMSA 1978, Section 62-9-5 to abandon its San Ysidro natural gas storage facility.

F. PNM shall comply with all requirements placed on it in this case, including matters involving future cases before the Commission.

G. Any outstanding matter not specifically ruled on is disposed of consistent with this Order.

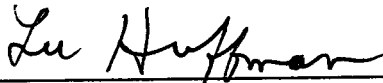
H. Copies of this Order shall be mailed to all persons listed on the official service list for this case.

I. This Order is effective immediately.

J. This Docket is hereby closed.

I S S U E D at Santa Fe, New Mexico this 23rd day of May, 2007.

NEW MEXICO PUBLIC REGULATION COMMISSION

A handwritten signature in black ink, appearing to read "Lee Huffman", is written over a horizontal line.

LEE W. HUFFMAN, Hearing Examiner

RECOMMENDED DECISION
EXHIBIT A

Page 1 of 8

1

	RATE BASE	Base Period	Test Period Adjustments	PGAC	Non PGAC Test Period	Hearing Examiner's Adjustments	Hearing Examiner's Cost of Svc
3							
4							
5							
6							
7	Net Plant In Service						
8	Production And Gathering	2,524,528	0	0	2,524,528		2,524,528
9	Underground Storage	281,737	(281,737)	0	0		0
10	Transmission	144,044,698	(2,596)	0	144,042,102		144,042,102
11	Distribution	238,556,259	0	0	238,556,259		238,556,259
12	General and Intangible	67,188,244	0	0	65,647,441	(70,091)	65,577,350
13	Total Net Plant	452,595,466	(1,825,136)	0	450,770,330	(70,091)	450,700,239
14							
15	Accumulated Deferred Income Taxes						
16	Pension Cost (190)	(7,672,101)	768,774	0	(6,903,327)	6,957,443	54,116
17	Accrued Vacation (190)	804,080	0	0	804,080		804,080
18	Contributions in Aid of Construction (190)	11,128,414	0	0	11,128,414		11,128,414
19	Capitalized Interest (190)	7,594,896	0	0	7,594,896		7,594,896
20	IRS Exams (190)	1,396,017	0	0	1,396,017		1,396,017
21	Post Employee Benefits--FAS 106 (190)	1,434,338	0	0	1,434,338		1,434,338
22	Regulatory Reserve (190)	(2)	2	0	0		0
23	Environmental Liability (190)	9,789	0	0	9,789		9,789
24	FAS 109 (190)	(530,213)	530,213	0	0		0
25	Workman's Compensation Liability (190)	293,449	0	0	293,449	351,407	644,856
26	General Liability Self Insurance (190)	202,933	0	0	202,933		202,933
27	General Reserve (190)	123,370	0	0	123,370		123,370
28	SFAS 123R - Stock Based Comp	0	322,721	0	322,721		322,721
29	Auto Self Insurance (190)	115,277	0	0	115,277		115,277
30	Tax Rate Adjustment (interco)	668,555	(668,555)	0	0		0
31	Liberalized Depreciation (282)	(69,872,935)	43,807	0	(69,829,128)		(69,829,128)
32	Amortization of IRS Exams (282)	(5,390,852)	0	0	(5,390,852)		(5,390,852)
33	FIN 47 -ARO	57,966	6,197	0	64,163		64,163
34	FAS 109 (282)	(17,440,569)	17,440,569	0	0		0
35	Acquisition Adjustment Amortization (282)	(37,786)	0	0	(37,786)		(37,786)
36	Tax Tax Flow Through Reversal (282)	(1,921,444)	0	0	(1,921,444)		(1,921,444)
37	Computer Software (283)	(2,972,445)	63,243	0	(2,909,202)		(2,909,202)
38	Bond Premium (283)	948,797	0	0	948,797		948,797
39	FAS 109 (283)	(5,062,667)	5,062,667	0	0		0
40	Purchased Gas Adjustment Clause--RR 4 (283)	(9,787,959)	9,787,959	0	0		0
41	Reacquired Debt (283)	41,809	0	0	41,809		41,809
42	Take or Pay Settlement--Rate Rider 8 (283)	(2,227,651)	2,227,651	0	0		0
43	Pension (283)	(1,807,840)	1,807,840	0	0		0
44	Rate Case Expense (283)	(136,646)	(4,734)	0	0	3,499	(137,881)
45	ERP Project	(86,108)	0	0	(86,108)		(86,108)
46	Mark to Market	1	(1)	0	0		0
47	Accrued Illness	10,813	0	0	10,813		10,813
48	Book Capitalized Interest	(276,693)	0	0	(276,693)		(276,693)
49	Prepaid Expenses	(299,010)	(249,469)	0	(548,479)		(548,479)
50	AFUDC Debt (282)	(340,917)	0	0	(340,917)		(340,917)
51							
52	Total Accumulated Deferred Income Taxes	(101,033,334)	37,138,884	0	(63,894,450)	7,312,349	(56,582,101)
53							
54							
55							

PUBLIC SERVICE COMPANY OF NEW MEXICO
COST OF SERVICE
FOR THE TEST PERIOD ENDED DECEMBER 31, 2005

RECOMMENDED DECISION
EXHIBIT A
Hearing Examiner's
Proposed Cost of Service
Page 2 of 8

		Base Period	Test Period Adjustments	PGAC	Non PGAC Test Period	Hearing Examiner's Adjustments	Hearing Examiner's Cost of Svc	
56								
57								
58	RATE BASE							
59								
60								
61	Subtractive Adjustments							
62	Gain on Reacquired Debt (257)	(542,144)	0	0	(542,144)		(542,144)	
63	Customer Advances (252)	(8,573,994)	125,435	0	(8,448,559)		(8,448,559)	
64	Customer Deposits (235)	(6,859,860)	0	0	(6,859,860)		(6,859,860)	
65	Retirement Work in Progress-RWIP (108.0)	536,828	0	0	536,828		536,828	
66	ARO Liability (230)	(184,161)	0	0	(184,161)		(184,161)	
66A	Injury & Damages Reserve	0	0	0	0	(1,628,836)	(1,628,836)	COS #2
67	Non Refundable CIAC (108)	(14,439,732)	0	0	(14,439,732)		(14,439,732)	
68								
69	Total Subtractive Adjustments	(30,063,063)	125,435	0	(29,937,628)	(1,628,836)	(31,566,464)	subtotal
70								
71	Additive Adjustments							
72	Construction Work in Progress-CWIP (107)	24,550,815	(7,224,731)	0	17,326,084	(6,589,308)	10,726,776	RB #1
73	Rights-of-Way (186)	1,372,107	0	0	1,372,107		1,372,107	
74	Rate Case Expenses (182)	172,581	184,529	0	357,110	(8,839)	348,271	RB #5
75	Loss on Reacquired Debt (189)	4,805,901	0	0	4,805,901		4,805,901	
76	Premium on Preferred Stock	0	567,448	0	567,448		567,448	
76A	Unamortized Litigation Costs	0	0	0	0	275,689	275,689	COS #15
77	Prepaid Pension Asset/AMPP	0	14,168,861	0	14,168,861	(17,573,739)	(3,404,878)	RB #2
78								
79	Total Additive Adjustments	30,901,404	7,696,107	0	38,597,511	(23,906,197)	14,691,314	subtotal
80								
81								
82	Working Capital							
83	Natural Gas Storage (164)	11,647,417	(7,476,742)	0	4,170,675		4,170,675	
84	Materials & Supplies (154)	2,173,681	(8,873)	0	2,164,808		2,164,808	
85	Stores Expense (163)	0	(61,572)	0	(61,572)		(61,572)	
86	Prepayments (165)	1,304,607	519,405	0	1,824,012		1,824,012	
87								
88	Subtotal Working Capital	15,125,705	(7,027,782)	0	8,097,923	0	8,097,923	
89								
90	Cash Working Capital	0	5,597,594	0	5,597,594	(84,200)	5,513,394	CALCULATED
91								
92	TOTAL RATE BASE	367,526,178	41,705,102	0	409,231,280	(18,376,975)	390,854,304	total
93								
94								

PUBLIC SERVICE COMPANY OF NEW MEXICO
COST OF SERVICE
FOR THE TEST PERIOD ENDED DECEMBER 31, 2005

RECOMMENDED DECISION
EXHIBIT A
Hearing Examiner's
Proposed Cost of Service
Page 3 of 8

		Base Period	Test Period Adjustments	PGAC	Non PGAC Test Period	Hearing Examiner's Adjustments	Hearing Examiner's Cost of Svc	
95								
96								
97								
98	OPERATIONS & MAINTENANCE EXPENSES							
99								
100								
101	Production O&M							
102	Natural Gas Production and Gathering	(2,831)	0	2,831	0		0	
103	Product Extraction	0	0	0	0		0	
104	Underground Storage	96,121	(58,668)	(5,924)	31,529		31,529	
105	Subtotal Production Expense	93,290	(58,668)	(3,093)	31,529	0	31,529	
106								
107	Other Production Expense							
108	Other Gas Supply	2,353,968	0	0	2,353,968		2,353,968	
109	Purchased Gas Costs	353,015,302	0	(353,015,302)	0		0	
110								
111	Total Production O&M	355,462,560	(58,668)	(353,018,395)	2,385,497	0	2,385,497	
112								
113	Transmission O&M	15,950,342	429,040	(10,968,961)	5,410,421	(308,855)	5,101,566	COS #14
114								
115	Distribution O&M	23,052,964	0	0	23,052,964		23,052,964	
116								
117	Customer Accounting	16,762,974	(1,494,657)	0	15,268,317	1,467,331	16,735,648	COS #1
118	Customer Service and Information	2,905,697	(270,677)	0	2,635,020	(262,296)	2,372,724	COS #12
119	Sales	78,939	(72)	0	78,867		78,867	
120	Total Customer Related O&M	19,747,610	(1,765,406)	0	17,982,204	1,205,035	19,187,239	subtotal
121								
122	Administrative and General	39,981,888	(4,662,140)	0	35,319,748	(3,566,447)	31,753,301	COS #3,6,11,13,15
123								
124	Total Operations and Maintenance	454,195,364	(6,057,174)	(363,987,356)	84,150,834	(2,670,267)	81,480,567	subtotal
125								
126								

EXPENSES	Base Period	Test Period Adjustments	PGAC	Non PGAC Test Period	Hearing Examiner's Adjustments	Hearing Examiner's Cost of Svc	
Depreciation/Amortization Expense							
Production--Manufactured Gas	78,152	(46)	0	78,106		78,106	
Underground Storage	26,586	(26,586)	0	0		0	
Transmission	3,587,002	155,188	0	3,742,190		3,742,190	
Distribution	14,333,366	452,657	0	14,786,023		14,786,023	
General and Intangible	7,862,415	1,032,760	0	8,895,175		8,895,175	
Subtotal Depreciation/Amortization	25,887,521	1,613,973	0	27,501,494	0	27,501,494	
CIAC Amortization	(668,959)	0	0	(668,959)		(668,959)	
Total Depreciation/Amortization Expense	25,218,562	1,613,973	0	26,832,535	0	26,832,535	
Taxes Other Than Income Taxes							
Property Taxes	3,413,182	404,275	0	3,817,457		3,817,457	
Payroll Taxes	2,886,449	(4,513)	0	2,881,936	(185,661)	2,696,275	COS #3 P/R TAX
Pipeline	227,027	0	0	227,027		227,027	
Inspection and Supervision Fee	2,111,038	(2,111,038)	0	0		0	
Native American	228,248	0	0	228,248		228,248	
Other General Taxes	62,750	0	0	62,750		62,750	
Total Taxes Other Than Income Taxes	8,928,694	(1,711,276)	0	7,217,418	(185,661)	7,031,757	subtotal
Miscellaneous Amortizations							
Amortization of Premium on Preferred Stock	0	71,362	0	71,362		71,362	
Amortization of Gain on Reacquired Debt	(74,544)	0	0	(74,544)		(74,544)	
Amortization of Loss on Reacquired Debt	638,487	0	0	638,487		638,487	
Accretion expense	0	15,653	0	15,653		15,653	
Total Miscellaneous Amortizations	563,943	87,015	0	650,958	0	650,958	
Miscellaneous Interest--Customer Deposits	0	294,974	0	294,974		294,974	
Total Operating Expenses	488,906,563	(5,772,488)	(363,987,356)	119,146,719	(2,855,928)	116,290,791	total

PUBLIC SERVICE COMPANY OF NEW MEXICO
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		Base Period	Test Period Adjustments	PGAC	Non PGAC Test Period	Hearing Examiner's Adjustments	Hearing Examiner's Cost of Svc	
173								
174								
175								
176								
177	INCOME TAXES							
178								
179								
180								
181	FEDERAL INCOME TAX							
182								
183	Total Rate Base	367,526,178	41,705,102	0	409,231,280	(18,376,975)	390,854,304	CALCULATED
184	Weighted Cost of Capital	8.47%			8.72%		7.96%	per A5
185								
186	Return on Rate Base	31,129,467	4,555,500	0	35,684,968	(4,560,067)	31,124,901	CALCULATED
187								
188	Less Return Adjustments							
189	Interest on LT Debt	(7,387,276)	(4,930,585)	0	(12,317,862)	553,147	(11,764,715)	CALCULATED
190	Tax Book Adjustments	76,377	232,327	0	308,704		308,704	
191	Non-deductible Meals	(273,940)	0	0	(273,940)		(273,940)	
192	AFUDC Equity	0	71,362	0	71,362		71,362	
193	Amortization of Premium on Preferred Stock	0	0	0	0		0	
194	Lobbying Expense	0	0	0	0		0	
195	Computer Software	0	0	0	0		0	
196	Amortization of Computer Software	3,459,339	(529,910)	0	2,929,429		2,929,429	
197	Amortization of Loss on Reacquired Debt	(399,122)	0	0	(399,122)		(399,122)	
198	Amortization of Gain on Reacquired Debt	613,560	0	0	613,560		613,560	
199	Pension Accrual Qualified	(1,760,689)	419,413	0	(1,341,276)		(1,341,276)	
200	Pension Accrual Non-Qualified	(70,844)	0	0	(70,844)		(70,844)	
201	Excess Tax Depreciation	(18,972,296)	13,595,206	0	(5,377,090)		(5,377,090)	
202	Amortization of IRS Exam	(636,872)	0	0	(636,872)		(636,872)	
203	Capitalized Interest	(827,194)	0	0	(827,194)		(827,194)	
204	Contributions in Aid of Construction	2,749,101	0	0	2,749,101		2,749,101	
205	401 (b) Contribution	(246,352)	0	0	(246,352)		(246,352)	
206	Take or Pay Settlements	(26,321)	26,321	0	0		0	
207	Rate Case Reserve	(345,161)	65,482	0	(279,669)		(279,669)	
208	Auto Self Insurance	(101,773)	0	0	(101,773)		(101,773)	
209	Gain/Loss Asset Disposition	(431,990)	431,990	0	0		0	
210	Stock Options	0	815,159	0	815,159		815,159	
211	Holiday Pay	8,332	0	0	8,332		8,332	
212	Accrued Vacation	12,792	0	0	12,792		12,792	
213	Accrued Illness	1,753	0	0	1,753		1,753	
214	Purchased Gas Adjustment	(24,723,892)	24,723,892	0	0		0	
215	Environmental Liability	(8,766)	0	0	(8,766)		(8,766)	
216	Workers Compensation	265,217	0	0	265,217		265,217	
217	General Liability Self Insurance	(106,298)	0	0	(106,298)		(106,298)	
218	Book Capitalized Interest	(9,509)	0	0	(9,509)		(9,509)	
219	Prepaid Expenses	(65,793)	(630,131)	0	(695,924)		(695,924)	
220	General Reserve	311,632	0	0	311,632		311,632	
221	FIN 47 ARO	146,421	15,653	0	162,074		162,074	
222	Deferred State Income Taxes	3,089,411	(2,748,676)	0	340,735		340,735	
223	Total Tax/Book Adjustments	(38,272,877)	36,488,098	0	(1,784,779)	0	(1,784,779)	
224	Total Return Adjustments	(45,660,154)	31,557,513	0	(14,102,641)	553,147	(13,549,494)	subtotal
225	Net Taxable Equity Return	(14,530,686)	36,113,013	0	21,582,327	(4,006,920)	17,575,407	total
226								
227								

	INCOME TAXES	Base Period	Test Period Adjustments	PGAC	Non PGAC Test Period	Hearing Examiner's Adjustments	Hearing Examiner's Cost of Svc	
228								
229								
230								
231								
232								
233								
234	Federal Tax Adjustments							
235								
236	Net Provision For Deferred Income Tax	0	0	0	0		0	
237	Computer Software	(1,210,769)	185,469	0	(1,025,300)		(1,025,300)	
238	Amortization of Computer Software	139,693	0	0	139,693		139,693	
239	Amortization of Loss on Reacquired Debt	(214,746)	0	0	(214,746)		(214,746)	
240	Amortization of Gain on Reacquired Debt	616,241	(146,795)	0	469,447		469,447	
241	Pension Accrual Qualified	24,795	0	0	24,795		24,795	
242	Pension Accrual Non-Qualified	6,640,304	(4,758,322)	0	1,881,982		1,881,982	
243	Excess Tax Depreciation	222,905	0	0	222,905		222,905	
244	Amortization of IRS Exam	289,518	0	0	289,518		289,518	
245	Capitalized Interest	(962,185)	0	0	(962,185)		(962,185)	
246	Contributions in Aid of Construction	86,223	0	0	86,223		86,223	
247	401 (b) Contribution	9,212	(9,212)	0	0		0	
248	Take or Pay Settlements	120,806	(22,922)	0	97,884		97,884	
249	Rate Case Reserve	35,621	0	0	35,621		35,621	
250	Auto Self Insurance	151,197	(151,197)	0	0		0	
251	Gain/Loss Asset Disposition	0	(285,306)	0	(285,306)		(285,306)	
252	Stock Options	(2,916)	0	0	(2,916)		(2,916)	
253	Holiday Pay	(4,477)	0	0	(4,477)		(4,477)	
254	Accrued Vacation	(614)	0	0	(614)		(614)	
255	Accrued Illness	8,653,362	(8,653,362)	0	0		0	
256	Purchased Gas Adjustment	3,068	0	0	3,068		3,068	
257	Environmental Liability	(92,826)	0	0	(92,826)		(92,826)	
258	Workers Compensation	37,204	0	0	37,204		37,204	
259	General Liability Self Insurance	3,328	0	0	3,328		3,328	
260	Book Capitalized Interest	(109,071)	220,546	0	243,573		243,573	
261	Prepaid Expenses	(51,247)	0	0	(51,247)		(51,247)	
262	General Reserve	(1,017,180)	962,037	0	(55,144)		(55,144)	
263	FIN 47 ARO	13,390,473	(12,664,543)	0	725,930	0	725,930	
264	Deferred State Income Taxes							
265	Total Provision for Deferred Income Tax							
266		(101,938)	0	0	(101,938)		(101,938)	
267	Investment Tax Credits	30,313	0	0	30,313		30,313	
268	Flow thru Amortization		0	0				
269								
270	Total Federal Tax Adjustments	13,318,848	(12,664,543)	0	654,305	0	654,305	
271								
272	Adjusted Equity Return	(1,211,838)	23,448,470	0	22,236,632	(4,006,920)	18,229,712	total
273	Federal Tax Factor (Rate/1-Rate)	53.846154%			53.846154%		53.846154%	
274								
275	Federal Income Tax	(652,528)	12,625,942	0	11,973,414	(2,157,415)	9,815,999	CALCULATED
276								
277	Less: Prov for Deferred Income Tax	13,390,473	(12,664,543)	0	725,930		725,930	
278	Flow thru Amortization	30,313	0	0	30,313		30,313	
279	ITC Amortization	(101,938)	0	0	(101,938)		(101,938)	
280								
281	Net Allowable F I T	12,666,320	(38,601)	0	12,627,719	(2,157,415)	10,470,304	subtotal
282								
283								
284								

PUBLIC SERVICE COMPANY OF NEW MEXICO
COST OF SERVICE
FOR THE TEST PERIOD ENDED DECEMBER 31, 2005

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INCOME TAXES	Base Period	Test Period Adjustments	PGAC	Non PGAC Test Period	Hearing Examiner's Adjustments	Hearing Examiner's Cost of Svc	
STATE INCOME TAX							
Return on Rate Base	31,129,467	4,555,500	0	35,684,968	(4,560,067)	31,124,901	CALCULATED
Less Return Adjustments:							
Interest on Long Term Debt	(7,387,276)	(4,930,565)	0	(12,317,862)	553,147	(11,764,715)	CALCULATED
Tax/Book Adjustments	(41,362,288)	39,236,774	0	(2,125,514)	0	(2,125,514)	
Accelerated Depreciation Flow Through	0	0	0	0	0	0	
Flow thru Amortization	183,181	0	0	183,181	0	183,181	
Add: Net Allowable F I T	12,666,320	(38,601)	0	12,627,719	(2,157,415)	10,470,304	CALCULATED
State Deferred Income Tax	<u>2,906,230</u>	<u>(2,748,676)</u>	<u>0</u>	<u>157,554</u>	<u>0</u>	<u>157,554</u>	
State Taxable Income	(1,864,366)	36,074,412	0	34,210,046	(6,164,336)	28,045,710	subtotal
State Tax Factor (Rate/1-Rate)	<u>7.596299%</u>			<u>7.596299%</u>		<u>7.596299%</u>	
State Income Tax	(141,623)	2,740,320	0	2,598,697	(468,261)	2,130,436	CALCULATED
Add: State Deferred Income Tax	<u>2,906,230</u>	<u>(2,748,676)</u>	<u>0</u>	<u>157,554</u>		<u>157,554</u>	
Flow thru Amortization	<u>183,181</u>	<u>0</u>	<u>0</u>	<u>183,181</u>		<u>183,181</u>	
Net Allowable S I T	2,947,788	(8,356)	0	2,939,432	(468,261)	2,471,171	subtotal
TOTAL FEDERAL & STATE INCOME TAXES	<u>15,614,108</u>	<u>(46,957)</u>	<u>0</u>	<u>15,567,151</u>	<u>(2,625,677)</u>	<u>12,941,475</u>	total

	REVENUE REQUIREMENT RECAP	Base Period	Test Period Adjustments	PGAC	Non PGAC Test Period	Hearing Examiner's Adjustments	Hearing Examiner's Cost of Svc	
314								
315								
316								
317								
318								
319								
320								
321	Return on Rate Base	31,129,467	4,555,500	0	35,684,968	(4,560,067)	31,124,901	CALCULATED
322								
323	Total Operating Expenses	488,906,563	(5,772,488)	(363,987,356)	119,146,719	(2,855,928)	116,290,791	CALCULATED
324								
325	Net Allowable Federal Income Tax	12,666,320	(38,601)	0	12,627,719	(2,157,415)	10,470,304	CALCULATED
326								
327	Net Allowable State Income Tax	<u>2,947,788</u>	(8,356)	<u>0</u>	<u>2,939,432</u>	(468,261)	<u>2,471,171</u>	CALCULATED
328								
329	Total Revenue Requirements Before Revenue							
330	Credits and Revenue Tax	535,650,138	(1,263,944)	(363,987,356)	170,398,838	(10,041,672)	160,357,166	subtotal
331								
332	Revenue Tax (Inspection and Supervision Fee)	0	2,685,360	(1,829,082)	856,278	(50,461)	805,817	CALCULATED
333								
334	Revenue Credits							
335	Late Payment Charges	(1,052,678)	0	0	(1,052,678)	292,411	(760,267)	MISC #1
336	Miscellaneous Service Charges	(6,008,454)	(202,633)	0	(6,211,087)		(6,211,087)	
337	Off-System Market-Based Transportation	(139,829)	0	0	(139,829)		(139,829)	
338	Off-System Discounted Transportation	0	0	0	0		0	
339	NGV Transportation Revenues	(81,082)	0	0	(81,082)		(81,082)	
340	Discounted On-System Transportation	(2,114,210)	0	0	(2,114,210)		(2,114,210)	
341	NGV Operating Revenues	0	0	0	0		0	
342	Off-System Sales Revenues	0	0	0	0		0	
343	Other Operating Revenues	<u>(167,803)</u>	<u>0</u>	<u>0</u>	<u>(167,803)</u>		<u>(167,803)</u>	
344								
345	Total Revenue Credits	(9,564,056)	(202,633)	0	(9,766,689)	292,411	(9,474,278)	subtotal
346								
347								
348	TOTAL REVENUE REQUIREMENTS	526,086,082	1,218,782	(365,816,438)	161,488,426	(9,799,721)	151,688,705	total

PUBLIC SERVICE COMPANY OF NEW MEXICO

Hearing Examiner's
Proposed Schedule A-1Summary of the Overall Cost of Service
and the Claimed Revenue Deficiency
For the Test Period Ending December 31, 2005

Line No.	Description	Base Period	Adjustments	PGAC	Non PGAC Test Period	Hearing Examiner's Adjustments	Hearing Examiner's Position
1	Purchased Gas Expense	353,015,302	0	(353,018,395)	0	0	0
2	Other Operations & Maintenance	101,180,062	(6,057,174)	(10,968,961)	84,150,834	(2,670,267)	81,480,567
3	Depreciation & Amortization	25,218,562	1,613,973	0	26,832,535	0	26,832,535
4	Miscellaneous Amortizations	563,943	87,015	0	650,958	0	650,958
5	Miscellaneous Interest	0	294,974	0	294,974	0	294,974
6	Taxes Other Than Income	8,928,694	(1,711,276)	0	7,217,418	(185,661)	7,031,757
7	Income Taxes	15,614,108	(46,957)	0	15,567,151	(2,634,129)	12,933,022
8	Return on Rate Base	31,129,467	4,555,500	0	35,684,968	(4,572,965)	31,112,003
9	Revenue Credits	(9,564,056)	(202,633)	0	(9,766,689)	292,411	(9,474,278)
10	Revenue Tax	<u>0</u>	<u>2,685,360</u>	<u>(1,829,082)</u>	<u>856,278</u>	<u>(50,568)</u>	<u>805,710</u>
11	Total Cost of Service	526,086,082	1,218,782	(365,816,438)	161,488,427	(9,821,179)	151,667,247
12	Gas Sales Revenue				<u>140,183,096</u>		140,183,096
13	Earnings Deficiency				21,305,331	(9,821,179)	11,484,151

PUBLIC SERVICE COMPANY OF NEW MEXICO

Hearing Examiner's
Proposed Schedule A-2

Summary of Cost of Service Adjustments
by Functional Classification
For the Test Period Ending December 31, 2005

Base Period	Adjustments	PGAC	Non PGAC Test Period	Hearing Examiner's	
				Adjustments	Position
353,015,302	0	(353,015,302)	0	0	0
(2,831)	0	2,831	0	0	0
0	0	0	0	0	0
96,121	(58,668)	(5,924)	31,529	0	31,529
2,353,968	0	0	2,353,968	0	2,353,968
15,950,342	429,040	(10,968,961)	5,410,421	(308,855)	5,101,566
23,052,964	0	0	23,052,964	0	23,052,964
16,762,974	(1,494,657)	0	15,268,317	1,467,331	16,735,648
2,905,697	(270,677)	0	2,635,020	(262,296)	2,372,724
78,939	(72)	0	78,867	0	78,867
39,981,888	(4,662,140)	0	35,319,748	(3,566,447)	31,753,301
25,218,562	1,613,973	0	26,832,535	0	26,832,535
563,943	87,015	0	650,958	0	650,958
0	294,974	0	294,974	0	294,974
8,928,694	(1,711,276)	0	7,217,418	(185,661)	7,031,757
15,614,108	(46,957)	0	15,567,151	(2,634,129)	12,933,022
31,129,467	4,555,500	0	35,684,968	(4,572,965)	31,112,003
(9,564,056)	(202,633)	0	(9,766,689)	292,411	(9,474,278)
0	<u>2,685,360</u>	<u>(1,829,082)</u>	<u>856,278</u>	<u>(50,568)</u>	<u>805,710</u>
526,086,082	1,218,782	(365,816,438)	161,488,427	(9,821,179)	151,667,247

PUBLIC SERVICE COMPANY OF NEW MEXICO

Hearing Examiner's
Proposed Schedule A-3

Summary of Rate Base
For the Test Period Ending December 31, 2005

Line No.	Description	Base Period	Adjustments	PGAC	Non PGAC Test Period	Hearing Examiner's Adjustments	Hearing Examiner's Position
Net Plant in Service							
1	Production & Gathering	2,524,528	0	0	2,524,528	0	2,524,528
2	Underground Storage	281,737	(281,737)	0	0	0	0
3	Transmission	144,044,698	(2,596)	0	144,042,102	0	144,042,102
4	Distribution	238,556,259	0	0	238,556,259	0	238,556,259
5	General & Intangible	67,188,244	(1,540,803)	0	65,647,441	(70,091)	65,577,350
7	Total Net Plant	452,595,466	(1,825,136)	0	450,770,330	(70,091)	450,700,239
8	Total Accum Deferred Income Taxes	(101,033,334)	37,138,884	0	(63,894,450)	7,312,349	(56,582,101)
9	Subtractive Adjustments	(30,063,063)	125,435	0	(29,937,628)	(1,628,836)	(31,566,464)
10	Additive Adjustments	30,901,404	7,696,107	0	38,597,511	(23,906,197)	14,691,314
Working Capital							
11	Natural Gas Storage (164)	11,647,417	(7,476,742)	0	4,170,675	0	4,170,675
12	Materials & Supplies (154)	2,173,681	(8,873)	0	2,164,808	0	2,164,808
13	Stores Expense (163)	0	(61,572)	0	(61,572)	0	(61,572)
14	Prepayments (165)	1,304,607	519,405	0	1,824,012	0	1,824,012
15	Cash Working Capital	0	5,597,594	0	5,597,594	(84,200)	5,513,394
16	Total Working Capital	15,125,705	(1,430,188)	0	13,695,517	(84,200)	13,611,317
17	Total Rate Base	367,526,178	41,705,102	0	409,231,280	(18,376,975)	390,854,304

RATE DESIGN - REVENUE DISTRIBUTION

Increase as											
Line No.	Rate No.	Rate of Return (%)	Relative Rate of Return	Percentage Increase		Test Period		Revenue Deficiency Distribution		Calculated Increase (%)	Percent of Total
				Calculated (%)	Allowed (%)	Cost of Service Revenue (\$)	Calculated (\$)	Adjusted (\$)			
(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	
1	10	6.2966%	1.0187	8.0899%	8.0899%	\$ 105,369,322	\$ 8,524,308	\$ 8,677,024	8.2349%	75.0133%	
2	30	7.7147%	1.2481	6.6028%	6.6028%	\$ 565,464	\$ 37,336	\$ 38,005	6.7211%	0.3286%	
3	31	6.3494%	1.0272	8.0226%	8.0226%	\$ 182,794	\$ 14,665	\$ 14,928	8.1664%	0.1291%	
4	35	5.6546%	0.9148	9.0084%	9.0084%	\$ 39,338	\$ 3,544	\$ 3,607	9.1698%	0.0312%	
5	37	14.5619%	2.3559	3.4981%	0.0000%	\$ 1,418	\$ -	\$ -	0.0000%	0.0000%	
6	54	6.1227%	0.9906	8.3196%	8.3196%	\$ 25,957,286	\$ 2,159,549	\$ 2,198,238	8.4687%	19.0039%	
7	56	7.4440%	1.2043	6.8429%	6.8429%	\$ 3,309,736	\$ 226,483	\$ 230,541	6.9655%	1.9930%	
8	58	7.0334%	1.1379	7.2424%	7.2424%	\$ 3,426,991	\$ 248,195	\$ 252,642	7.3721%	2.1841%	
9	61	41.0389%	6.6394	1.2412%	0.0000%	\$ 57,236	\$ -	\$ -	0.0000%	0.0000%	
10	70	1.4351%	0.2322	35.4950%	10.3013%	\$ 1,105,140	\$ 113,844	\$ 115,883	10.4859%	1.0018%	
11	114	3.1322%	0.5067	16.2627%	10.3013%	\$ 347,553	\$ 35,802	\$ 36,444	10.4859%	0.3151%	
12	Total	6.1811%	1.0000	8.2410%		\$ 140,362,278	\$ 11,363,727	\$ 11,567,312	8.2410%	100.0000%	

SCEDULE: Rates
FROM: 01/05
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PNM
GAS SERVICES
REVENUE ANALYSIS

RECOMMENDED DECISION
EXHIBIT C

**Rate No. 10
Residential**

	Approved 03-0017-UT Rates		
	Quantity	Rate	Revenue
Service Charge	5,361,178	\$ 8.00	\$ 48,250,601
Commodity			
Transmission	285,822,873	\$ 0.0383	\$ 10,947,016
Distribution	299,039,537	\$ 0.1544	\$ 46,171,705
Total Billing			\$ 105,369,322

Proposed Rates

	Approved 03-0017-UT Rates		
	Quantity	Rate	Revenue
Service Charge	5,361,178	\$ 10.26	\$ 55,005,685
Commodity			
Transmission	285,822,873	\$ 0.0375	\$ 10,718,356
Distribution	299,039,537	\$ 0.1610	\$ 48,145,366
Total Proposed Billing			\$ 113,869,409
Revenue Allocation			\$ 114,046,346
Over (Under) Recovery			\$ (176,937)

**Rate No. 30
Irrigation**

	Approved 03-0017-UT Rates		
	Quantity	Rate	Revenue
Service Charge	7,725	\$ 27.00	\$ 208,567
Commodity			
Transmission	3,967,913	\$ 0.0326	\$ 129,354
Distribution	6,671,091	\$ 0.0341	\$ 227,543
Total Billing			\$ 565,464

Proposed Rates

	Approved 03-0017-UT Rates		
	Quantity	Rate	Revenue
Service Charge	7,725	\$ 27.00	\$ 208,567
Commodity			
Transmission	3,967,913	\$ 0.0361	\$ 143,242
Distribution	6,671,091	\$ 0.0375	\$ 250,166
Total Proposed Billing			\$ 601,975
Revenue Allocation			\$ 603,469
Over (Under) Recovery			\$ (1,494)

**Rate No. 31
Water & Sewage Pumping**

	Approved 03-0017-UT Rates		
	Quantity	Rate	Revenue
Service Charge	216	\$ 70.00	\$ 15,120
Commodity			
Transmission	2,306,473	\$ 0.0303	\$ 69,886
Distribution	2,306,473	\$ 0.0399	\$ 92,028
Total Billing			\$ 182,794

Proposed Rates

	Approved 03-0017-UT Rates		
	Quantity	Rate	Revenue
Service Charge	216	\$ 80.00	\$ 17,280
Commodity			
Transmission	2,306,473	\$ 0.0337	\$ 77,728
Distribution	2,306,473	\$ 0.0416	\$ 95,949
Total Proposed Billing			\$ 197,257
Revenue Allocation			\$ 197,722
Over (Under) Recovery			\$ (465)

**Rate No. 35
Cogeneration**

	Approved 03-0017-UT Rates		
	Quantity	Rate	Revenue
Service Charge	24	\$ 30.00	\$ 720
Commodity			
Transmission	571,713	\$ 0.0274	\$ 15,665
Distribution	571,713	\$ 0.0349	\$ 19,953
Total Billing			\$ 39,338

Proposed Rates

	Approved 03-0017-UT Rates		
	Quantity	Rate	Revenue
Service Charge	24	\$ 41.00	\$ 984
Commodity			
Transmission	571,713	\$ 0.0303	\$ 17,323
Distribution	571,713	\$ 0.0357	\$ 20,410
Total Proposed Billing			\$ 42,857
Revenue Allocation			\$ 42,945
Over (Under) Recovery			\$ (88)

**Rate No. 37
Gas Air Conditioning**

	Approved 03-0017-UT Rates		
	Quantity	Rate	Revenue
Service Charge	12	\$ 15.00	\$ 180
Commodity			
Transmission	-	\$ 0.0259	\$ -
Distribution	38,089	\$ 0.0325	\$ 1,238
Total Billing			\$ 1,418

Proposed Rates

	Approved 03-0017-UT Rates		
	Quantity	Rate	Revenue
Service Charge	12	\$ 15.00	\$ 180
Commodity			
Transmission	-	\$ 0.0259	\$ -
Distribution	38,089	\$ 0.0325	\$ 1,238
Total Proposed Billing			\$ 1,418
Revenue Allocation			\$ 1,418
Over (Under) Recovery			\$ -

**Rate No. 54
Small Volume General Service**

	Approved 03-0017-UT Rates		
	Quantity	Rate	Revenue
Service Charge	464,568	\$ 15.00	\$ 6,968,436
Commodity			
Transmission	152,115,926	\$ 0.0613	\$ 9,329,110
Distribution	159,071,264	\$ 0.0607	\$ 9,659,740
Total Billing			\$ 25,957,286

Proposed Rates

	Approved 03-0017-UT Rates		
	Quantity	Rate	Revenue
Service Charge	464,568	\$ 16.50	\$ 7,665,365
Commodity			
Transmission	152,115,926	\$ 0.0655	\$ 9,963,593
Distribution	159,071,264	\$ 0.0658	\$ 10,466,899
Total Proposed Billing			\$ 28,095,847
Revenue Allocation			\$ 28,155,524
Over (Under) Recovery			\$ (59,677)

SCEDULE: Rates
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PNM
 GAS SERVICES
 REVENUE ANALYSIS

RECOMMENDED DECISION
 EXHIBIT C

Rate No. 56
Medium Volume General Service
 Approved 03-0017-JT Rates

	Quantity	Rate	Revenue
Service Charge	1,105	\$ 60.00	\$ 66,315
Commodity			
Transmission	37,832,706	\$ 0.0441	\$ 1,668,421
Distribution	34,463,949	\$ 0.0457	\$ 1,575,000
Total Billing			3,309,736

	Quantity	Rate	Revenue
Service Charge	1,105	\$ 66.00	\$ 72,947
Commodity			
Transmission	37,832,706	\$ 0.0475	\$ 1,797,054
Distribution	34,463,949	\$ 0.0482	\$ 1,661,162
Total Proposed Billing			\$ 3,531,163
Revenue Allocation			\$ 3,540,277
Over (Under) Recovery			\$ (9,114)

Rate No. 58
Large Volume General Service
 Approved 03-0017-JT Rates

	Quantity	Rate	Revenue
Service Charge	124	\$ 1,000.00	\$ 124,000
Commodity			
Transmission	54,855,946	\$ 0.0399	\$ 2,188,752
Distribution	30,695,281	\$ 0.0363	\$ 1,114,239
Total Billing			\$ 3,426,991

	Quantity	Rate	Revenue
Service Charge	124	\$ 1,000.00	\$ 124,000
Commodity			
Transmission	54,855,946	\$ 0.0435	\$ 2,386,234
Distribution	30,695,281	\$ 0.0376	\$ 1,154,143
Total Proposed Billing			\$ 3,664,377
Revenue Allocation			\$ 3,679,633
Over (Under) Recovery			\$ (15,256)

Rate No. 61
Sales For Resale
 Approved 03-0017-JT Rates

	Quantity	Rate	Revenue
Service Charge	24	\$ 2,000.00	\$ 48,000
Commodity			
Transmission	294,146	\$ 0.0314	\$ 9,236
Distribution	-	\$ -	\$ -
Total Billing			\$ 57,236

	Quantity	Rate	Revenue
Service Charge	24	\$ 2,000.00	\$ 48,000
Commodity			
Transmission	294,146	\$ 0.0314	\$ 9,236
Distribution	-	\$ -	\$ -
Total Proposed Billing			\$ 57,236
Revenue Allocation			\$ 57,236
Over (Under) Recovery			\$ -

Rate No. 70 (2L)
Off-System Transportation
 Approved 03-0017-JT Rates

	Quantity	Rate	Revenue
Service Charge	-	\$ -	\$ -
Commodity			
Transmission	74,671,600	\$ 0.0148	\$ 1,105,140
Distribution	-	\$ -	\$ -
Total Billing			1,105,140

	Quantity	Rate	Revenue
Service Charge	-	\$ -	\$ -
Commodity			
Transmission	74,671,600	\$ 0.0163	\$ 1,217,147
Distribution	-	\$ -	\$ -
Total Proposed Billing			\$ 1,217,147
Revenue Allocation			\$ 1,221,023
Over (Under) Recovery			\$ (3,876)

Rate No. 114
District Energy Systems
 Approved 03-0017-JT Rates

	Quantity	Rate	Revenue
Service Charge	12	\$ 1,200.00	\$ 14,400
Commodity			
Transmission	6,771,418	\$ 0.0228	\$ 154,388
Distribution	6,771,418	\$ 0.0264	\$ 178,765
Total Billing			347,553

	Quantity	Rate	Revenue
Service Charge	12	\$ 1,200.00	\$ 14,400
Commodity			
Transmission	6,771,418	\$ 0.0278	\$ 188,245
Distribution	6,771,418	\$ 0.0267	\$ 180,797
Total Proposed Billing			\$ 383,442
Revenue Allocation			\$ 383,997
Over (Under) Recovery			\$ (555)

SCEDULE: Proof of Revenue
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PNM GAS SERVICES
 TOTAL REVENUE
 NEW MEXICO JURISDICTIONAL

RECOMMENDED DECISION
 EXHIBIT D

RATE DESIGN - PROOF OF REVENUE

Line No. (a)	Rate Schedule (b)	Test Year Revenues (c)	Proposed Revenue Changes (d)	Total Revenues (e)	Calculated Revenues From Sch. P-3 (f)	Over (Under) Recovery (g)
1	Cost of Service Revenues					
2	10	\$ 105,369,322	\$ 8,677,024	\$ 114,046,346	\$ 113,869,409	\$ (176,937)
3	30	565,464	38,005	603,469	601,975	(1,494)
4	31	182,794	14,928	197,722	197,257	(465)
5	35	39,338	3,607	42,945	42,857	(88)
6	37	1,418	-	1,418	1,418	-
7	54	25,957,286	2,198,238	28,155,524	28,095,847	(59,677)
8	56	3,309,736	230,541	3,540,277	3,531,163	(9,114)
9	58	3,426,991	252,642	3,679,633	3,664,377	(15,256)
10	61	57,236	-	57,236	57,236	-
11	70	1,105,140	115,883	1,221,023	1,217,147	(3,876)
	114	347,553	36,444	383,997	383,442	(555)
12	Total Cost of Service Revenues	\$ 140,362,278	\$ 11,567,312	\$ 151,929,590	\$ 151,662,128	\$ (267,462)
13	Cost of Gas Revenues	364,772,027	-	364,772,027	364,772,027	-
14	Natural Gas Processed By Others	-	-	-	-	-
15	Other Operating Revenues	9,474,277	-	9,474,277	9,474,277	-
16	Total Operating Revenues	\$ 514,608,582	\$ 11,567,312	\$ 526,175,894	\$ 525,908,432	\$ (267,462)

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF THE APPLICATION)
OF PUBLIC SERVICE COMPANY OF NEW)
MEXICO FOR A REVISION TO ITS RATES,)
RULES, AND CHARGES PURSUANT TO)
ADVICE NOTICE NOS. 755 AND 756,)

Case No. 06-00210-UT

PUBLIC SERVICE COMPANY OF NEW MEXICO,)

Petitioner.)

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of **Recommended Decision of the Hearing Examiner**, issued May 23, 2007, was mailed first-class, postage prepaid, to each of the following:

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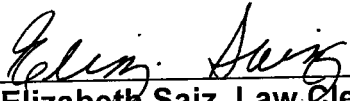
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Electric Utility Director
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DATED this **23rd** May, 2007.

NEW MEXICO PUBLIC REGULATION COMMISSION



Elizabeth Saiz, Law Clerk

BEFORE THE WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

WUTC V. PSE

DOCKET NOS. UE-060266 AND UG-060267

DIRECT TESTIMONY OF MICHAEL L. BROSCH (MLB-1T)

ON BEHALF OF

PUBLIC COUNSEL

DATED JULY 19, 2006

NON-CONFIDENTIAL

DIRECT TESTIMONY OF MICHAEL L. BROSCH (MLB-1T)
Docket Nos. UE-060266 and UG-060267

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MICHAEL BROSCH'S EXHIBIT LIST

Exhibit No. ____ (MLB-2) Summary of Qualifications

Exhibit No. ____ (MLB-3) Prior Testimony Listing

I. INTRODUCTION AND QUALIFICATIONS

Q. Please state your name and business address.

A. My name is Michael L. Brosch. My business address is 740 North Blue Parkway, Suite 204, Lee's Summit, Missouri 64086.

Q. By whom are you employed?

A. I am a principal in the firm Utilitech, Inc., a consulting firm engaged primarily in utility rate and regulation work. The firm's business and my responsibilities are related to special services work for utility regulatory clients. These services include rate case reviews, cost of service analyses, jurisdictional and class cost allocations, financial studies, rate design analyses and focused investigations related to utility operations and ratemaking issues.

Q. On whose behalf are you appearing in this proceeding?

A. I am appearing on behalf of the Washington Attorney General – Public Counsel Section ("Public Counsel"). Utilitech entered into a contract with Public Counsel to review and respond to certain non-traditional rate tracking proposals raised by Puget Sound Energy, Inc. ("Puget" or "Company") as part of its recommendations within its filing for an increase in its electric and gas rates and revenues.

Q. Will you summarize your educational background and professional experience in the field of utility regulation?

A. Exhibit No. ____ (MLB-2) is a summary of my education and professional qualifications. I have testified before utility regulatory agencies in Arizona, Arkansas, California, Florida, Hawaii, Illinois, Indiana, Iowa, Kansas, Michigan,

1 Missouri, New Mexico, Ohio, Oklahoma, Utah, Washington and Wisconsin in
2 regulatory proceedings involving electric, gas, telephone, water, sewer, transit, and
3 steam utilities. In Washington I have testified in several major proceedings before
4 the Commission, including Sprint's spinoff of its local telecommunications division
5 (UT-051291), U S West rate cases (UT-950200, UT-970766), the U S West/Qwest
6 merger (UT-991358), the most recent Verizon rate case (UT-040788) and the
7 regulatory accounting for, and later sale of Qwest's directory publishing business
8 (UT-980948 and UT-021120).

9 **Q. Have you previously participated in energy utility regulatory proceedings?**

10 A. Yes. I have participated in many electric and gas regulatory proceedings, as listed
11 and described in Exhibit No. ____ (MLB-3). While much of my experience involves
12 traditional rate increase or rate reduction cases, I have also addressed rate
13 adjustment tracking tariffs as well as deferral accounting proposals on many prior
14 occasions.

15 **Q. What is the purpose of your testimony in this docket?**

16 A. My testimony is intended to respond, on behalf of Public Counsel, to certain
17 regulatory policy concerns raised by two proposed rate adjustment tracking
18 mechanisms being advocated by Puget Sound Energy. The first proposed new
19 tracking mechanism would increase electric and gas utility service rates between
20 future PSE rate cases on a single-issue basis using a "Depreciation Tracker" to
21 account for increases in depreciation expense that are anticipated by the Company.¹

¹ John H. Story Direct Testimony, Exhibit No. ____ (JHS-1T), pp. 73-78.

1 The second new rate tracking mechanism would partially “decouple” gas margin
2 recovery to account for variations in usage per customer between rate cases through
3 a proposed Gas Revenue Normalization Adjustment (“GRNA”) tariff.² My
4 testimony explains several problems arising from PSE’s proposed new Depreciation
5 Tracker and GRNA decoupling rate adjustment proposals and recommends that
6 these mechanisms not be approved by the Commission.

7 **Q. Please summarize the recommendations that are set forth in your testimony.**

8 A. In general, I recommend that the Commission not approve piecemeal rate
9 adjustment tracking tariffs for isolated elements of utility revenue requirements in
10 the absence of compelling evidence that such piecemeal rate adjustments are
11 warranted. My testimony explains how traditional test-year regulation achieves a
12 balanced measurement of revenue requirements. I then describe how tracking
13 tariffs and deferral accounting methods can be used as exceptions to the normal
14 test-year approach, when warranted by extraordinary circumstances. I explain
15 several general criteria that should be satisfied before piecemeal cost tracking tariffs
16 should be accepted by regulators. When these criteria are applied to the specific
17 depreciation tracking and gas revenue GRNA decoupling mechanisms Puget has
18 proposed, I demonstrate why the Company’s proposals should be rejected by the
19 Commission.

² Ronald J. Amen Direct Testimony, Exhibit No. ____ (RJA-1T), pp. 27-57.

1 Q. How is the balance of your testimony organized?

2 A. My testimony is arranged by major topical area. A Table of Contents appearing at
3 the beginning of the testimony sets forth this organization.

4 II. TEST PERIOD RATEMAKING CONCEPTS

5 **Q. What is a test period and how is it used in utility regulation?**

A. Energy utilities have traditionally been regulated based upon their cost to provide service, including an opportunity to earn a reasonable return on invested capital. The process used to evaluate and measure the cost of service and resulting revenue requirement is the rate case, in which a balanced review of jurisdictional expenses, rate base investment, the cost of capital and revenues at present rates can be undertaken at a common point in time, referred to as a “test period.” See, e.g., *WUTC v. Avista Corporation*, Docket Nos. UE-991606, UG-991607, Third Supplemental Order, ¶¶ 14-16; *WUTC v. Washington Water Power*, Cause Nos. U-81-15, U-81-16, Second Supplemental Order, pp. 6-7 (rejecting company request for projected future test year, stating “[t]raditionally, this Commission has adopted the historical test year [.]”). In Washington, the test period is usually a recent actual 12-month period of time within which revenues at present rate levels are compared to operating expenses and the required return on average rate base, to determine whether an overall increase or reduction in revenue levels is needed. *Id.*; *WUTC v. Puget Sound Power & Light Co.*, UE-920433, 920499, 921262, Eleventh Supplemental Order, pp. 4-5.

1 It is essential for this synchronized review of both revenue levels and cost
2 levels to occur within a carefully structured test period, because both revenues and
3 costs tend to change with the passage of time as customers are added, inflation and
4 productivity changes impact costs, capital market conditions change and sales
5 volumes fluctuate. The dynamic nature of utility costs and revenues does not
6 necessarily imply frequent rate cases. As long as revenues and costs remain in
7 approximate balance, causing the utility's earnings to stay within acceptable
8 proximity to authorized return levels, an electric or gas utility may be able go many
9 years between rate cases.

10 An important element of traditional test period regulation is the incentive
11 created for management to control and reduce costs, so as to maximize the
12 opportunity to actually earn at or above the authorized return level between rate case
13 test periods.

14 Another beneficial characteristic of traditional test year regulation is the
15 intensive focus upon utility operations and costs within a formal proceeding in
16 which Commission Staff and other interested parties can carefully examine or audit
17 the components making up the revenue requirement. In contrast, piecemeal rate
18 tracking tariff adjustments often receive little scrutiny or input from consumer
19 representatives, even though significant customer impacts can result from such
20 tariffs. These mechanisms place an added burden on Commission Staff and
21 intervenors, and ultimately, regulatory bodies are likely to give less scrutiny to these
22 costs.

1 **Q. Under traditional test-period rate case regulation, what normally happens**
2 **when a specific utility expense increases between test periods?**

3 A. Increases in specific individual expenses between test periods, if nothing else
4 changes, would directly impact the utility's pre-tax earnings and the achieved rate of
5 return. However, all of the utility's costs and revenues tend to change over time.
6 Customer and revenue growth or reductions in other costs often serve to offset or
7 mitigate isolated cost changes, such that a utility company may be able to avoid rate
8 increases for extended periods of time.

9 Sustained cost increases that were not offset by reductions in other costs or
10 by increases in customer and sales levels may contribute to declines in achieved
11 returns sufficient to justify the filing of a petition to increase rates. However,
12 whenever a rate case occurs, all of the elements of revenue requirement are again
13 measured and adjusted, in a balanced overall review that should account for cost
14 increases in some areas being offset by cost savings in other areas. For example,
15 Puget is forced to account for its higher customer count and sales volumes and its
16 current capital market conditions and cost of capital in this docket, at the same time
17 it has proposed to recognize a larger rate base and increased depreciation expenses.
18 This balanced review of all elements of revenue requirement is a key characteristic
19 of traditional regulation.

1 **Q. You mentioned an “incentive” effect that results from traditional test period**
2 **regulation. What is the incentive that is created?**

3 A. Once revenues and costs are measured within the rate case test period, all changes
4 such as cost reductions or sales margin growth cause improvements in the achieved
5 actual return level, relative to Commission-authorized returns and are “favorable”
6 from the shareholder perspective. Shareholders are rewarded with higher earnings
7 between test years when management is able to successfully minimize cost
8 increases, maximize productivity gains, or add profitable new customers to the
9 system. Conversely, unfavorable changes between test years, such as cost increases
10 or sales revenue declines can contribute to earnings below authorized levels.
11 Punishment in the form of reduced earnings occurs when expense increases or sales
12 and margin losses between rate case test periods are not fully offset by revenue
13 gains. In this way, regulatory lag provides a symmetrical incentive for management
14 that can either reward cost containment and the profitable growth in sales or
15 temporarily punish excessive cost increases until the time when a new rate case can
16 be litigated.

17 **Q. Does the use of projected or “future” test period approach, as compared to the**
18 **actual or “historical” test period approach that is used in Washington, change**
19 **the balance that is achieved among test period ratemaking elements?**

20 A. No. A balanced and matched measurement of the revenue requirement elements is
21 still pursued. Several state regulatory commissions employ projected (aka “future”)
22 test period ratemaking using budgeted information, rather than actual recorded

1 accounting data from a historical year. Use of such projected test period financial
2 data introduces management, staff and intervenor judgment and debate regarding
3 how sales volumes, employment levels, non-labor expenses and rate base
4 investments may change in the future rate-setting period. However, the desired end-
5 result is still a matched comparison of revenues to costs within an internally
6 consistent test period. The test year approach used, projected versus historical, does
7 not change the need for a balanced comparison of revenues at present rates to the
8 overall cost of service in order to determine rate changes that are needed.
9 Unfortunately, while presumed to be desirable at reducing regulatory lag, projected
10 test year analyses are inherently more complex in practice because of difficulties
11 associated with accurately predicting future events, documenting assumed future
12 events in the absence of factual data and the challenges involved in defending such
13 predictions upon critical review in a litigation setting.

14 **Q. What are the most common types of exceptions to the standard approaches to**
15 **test period rate case regulation of energy utilities that you have described?**

16 A. Exceptions to the synchronized test period review of revenues and costs have been
17 allowed in limited instances by regulators for certain large and volatile cost
18 elements that are beyond the control of utility management and that might produce
19 unacceptable financial outcomes if not allowed special treatment. The most
20 common exception to traditional test period regulation is the widespread utilization
21 of purchased energy adjustment clauses to periodically adjust rates, so as to track
22 changes in the costs of purchased gas for local gas distribution utilities or to track

1 changes in the costs of generation fuel and/or purchased power incurred by electric
2 utilities. Power Cost Adjustment (“PCA”) and Purchased Gas Adjustment (“PGA”)
3 mechanisms are employed by many state regulators because fuel and purchased
4 energy commodity costs are recognized to be:

- 5 • Large in relation to the total cost to provide electric service, and
- 6 • Subject to market forces (rather than management control), and
- 7 • Volatile and difficult to reasonably quantify in rate cases, and
- 8 • Substantial enough to cause potential earnings volatility if not tracked.

9 Another exception to traditional test period regulation that occurs with
10 some regularity is the concept of deferral accounting, which is sometimes referred
11 to as an accounting authority order. For designated transactions or types of costs,
12 the utility may be allowed to deviate from the accounting otherwise required under
13 Generally Accepted Accounting Principles (“GAAP”) or the Federal Energy
14 Regulatory Commission (“FERC”) accounting principles set forth in the Uniform
15 System of Accounts (“USOA”). Examples of accounting deferral orders might
16 include extraordinary storm recovery costs or deferral of costs associated with
17 merger transaction and transition costs, in an effort to mitigate the financial impact
18 of extraordinary events or to better match cost recognition to the periods thought to
19 benefit from a merger of utility entities.

1 **Q. Has the Commission noted any of these considerations in allowing Power Cost**
2 **Adjustment mechanisms in Washington?**

3 A. Yes. In its recent decision in the PacifiCorp rate case, the Commission reaffirmed
4 certain principles that should be incorporated in a properly designed PCA, stating
5 the following:

- 6 • “The purpose is to recognize variability in the cost of operating *existing*
7 power supply resources as a result of abnormal weather conditions that are
8 out of a utility’s control. Ratepayers understand the connection between
9 weather and rates;
- 10 • Power cost adjustment mechanisms are *short-run* accounting procedures
11 to address *short-run* cost changes resulting from unusual weather;
- 12 • It is not appropriate to include new resources in a power cost adjustment
13 mechanism. New resources must be considered in general rate cases or
14 power cost only rate cases;
- 15 • Ratepayers should receive the benefit of a reduction in cost of capital, as a
16 power cost adjustment introduces rate instability for ratepayers and
17 earnings stability for stockholders, and;
- 18 • Power cost adjustment mechanisms should not interfere with least cost
19 planning, conservation, or other regulatory goals.³

³ *WUTC v. PacifiCorp*, Docket No. UE-050684, Order No. 4 at ¶ 91 (April 17, 2006). (“2006 PacifiCorp GRC Order”). Citations omitted, emphasis in original.

1 **Q. Why is a discussion of traditional test period regulation, versus rate tracking**
2 **and deferral accounting, relevant to this Puget rate case proceeding?**

3 A. As noted above, Puget is requesting Commission approval of two new piecemeal
4 rate tracking devices to change rate levels between rate cases for increased
5 depreciation expenses and for post-test-year changes in gas usage per customer.
6 Public Counsel, on the other hand, seeks to restrict the use of these exceptional
7 regulatory treatment to only instances where there is compelling evidence that
8 piecemeal ratemaking is in the public interest. It is my belief that parties to
9 regulatory proceedings should not be allowed to tinker with the balance inherent in
10 traditional test period ratemaking processes by isolating certain revenue or cost
11 elements for rate tracking or deferral accounting treatment in the absence of
12 compelling evidence that traditional regulation is not working effectively. The
13 testimony that follows explains certain generalized criteria that the Commission
14 should consider in evaluating requests by energy utilities to selectively depart from
15 balanced test period regulation in changing rates and revenues and then applies such
16 criteria to Puget's specific new rate tracking proposal in this Docket.

17 **Q. What general problems are created by the use of Rate Trackers, Accounting**
18 **Deferrals and Rate Case True-up devices?**

19 A. The general problem associated with use of these regulatory tools is the potentially
20 serious distortion of the "matching" that is desirable in a rate case test year. This is
21 often referred to as the "matching" principle in ratemaking – which recognizes the
22 importance of matching all revenues and costs (expenses, rate base, rate of return)

1 at a consistent period of time to determine needed changes in utility pricing. I
2 understand that the Commission has recognized this principle in a recent Avista
3 case in its findings regarding an adjustment for the Coyote Springs II generating
4 plant. The Commission's Order states in part: "The matching principle requires that
5 all cost-of-service components – revenue, investment, expenses and cost of capital –
6 must be considered and evaluated at a similar point in time." *WUTC v. Avista*
7 *Corporation*, UE-050482, UT-050483, Order No. 5, ¶ 111.

8 As I mentioned in prior testimony, all elements of the revenue requirement
9 calculation are dynamic through time and changes that are favorable tend to offset
10 other changes that are unfavorable. For example, adding customers and the related
11 revenue growth can help "pay for" increases in operating expenses, while growth in
12 the depreciation reserve tends to offset to some degree the construction activity that
13 adds new Plant in Service.⁴ If a party is allowed to select certain items for special
14 treatment with a rate tracker or through deferral accounting, one can reasonably
15 expect that the selected items will be "cherry picked" by that advocate so as to
16 influence the regulatory process to the sole advantage of that party. Other specific
17 concerns with these regulatory exceptions to balanced test year analysis include:

- 18 • Reduction of management incentives (by eliminating regulatory lag),

⁴ New customers increase utility sales volumes, yielding margin revenues (revenues less fuel costs) that contribute toward recovery of the fixed costs of the business. Some incremental non-fuel costs may also be caused by adding new customers, if facilities extensions are required that exceed advances or contributions pursuant to tariff or rule.

- 1 • Shifting of cost responsibility and risk to customers who are least able to
- 2 influence cost levels or sales levels.
- 3 • Increases in tariff and bill complexity that may be difficult to explain to
- 4 customers or that may complicate customers' ability to control their costs.
- 5 • Administrative complexity and costs associated with audit verification,
- 6 administration of complex accounting entries, cost allocations and/or tariff
- 7 calculations, often on an accelerated procedural schedule.
- 8 • Potential for inadequate regulatory oversight and auditing of tariff
- 9 application.

10 With these concerns in mind, the exceptions to normal test year ratemaking using
11 rate trackers and/or deferral accounting should only be allowed when extraordinary
12 circumstances exist that preclude the setting of just and reasonable rates through
13 traditional test year procedures.

14 **Q. Under what circumstances should regulators consider adoption of tracking**
15 **tariffs and/or regulatory deferral accounting for specific changes that occur**
16 **between rate case test years?**

17 **A.** Rate trackers and cost deferrals should be approved only in instances where
18 compelling circumstances justify departure from traditional test period review of all
19 costs and revenues within rate case proceedings in which the overall revenue
20 requirement can be audited and considered in a balanced and synchronized manner.
21 Costs or revenue changes to be deferred or rate tracked should generally have all of

1 the following attributes to merit such exceptional and preferential rate recovery
2 treatment:

- 3 1. Substantial enough to have a material impact upon revenue
4 requirements and the financial performance of the business between
5 rate cases.
- 6 2. Beyond the control of management, where utility management has
7 little influence over experienced revenue or cost levels.
- 8 3. Volatile in amount, causing significant swings in income and cash
9 flows if not tracked.
- 10 4. Straightforward and simple to administer, readily audited and verified
11 through expedited regulatory reviews.
- 12 5. Balanced and not distortive of test period relationships –reflective of
13 factors that mitigate impacts in a manner that preserves test year
14 matching principles.

15 In the testimony that follows, I will apply these general criteria to the two proposed
16 rate trackers being advocated by PSE, so as to illustrate why these Company
17 proposals should be rejected.

18 **Q. Do regulated utilities in Washington, if they experience significant attrition that**
19 **compromises their financial strength, have any options for regulatory relief other**
20 **than piecemeal ratemaking trackers or deferrals?**

21 A. Yes. In general, past Commission orders show that Washington utilities have been
22 allowed interim or emergency rate relief when facing very serious financial

1 circumstances, if required factors are present.⁵ In the event PSE actually experiences
2 serious attrition problems under traditional regulation in the future, the Company may
3 be able to qualify for interim or emergency rate relief as a remedy for such problems.

4 **III. REGULATORY LAG IS SYMMETRICAL AND PROMOTES**
5 **EFFICIENCY**
6

7 **Q. In previous testimony, you described how the balanced measurement of all**
8 **elements of the revenue requirement within a test period is important. What is**
9 **“regulatory lag” and how does it impact utility regulation?**

10 A. Regardless of whether we use actual historical test period data or projected future test
11 period financial estimates to determine public utility revenue requirements, there will
12 always be a “lag” between the timing of available financial data that is incorporated
13 into evidence relied upon by the regulator and the subsequent period of time during
14 which new utility rates are effective. Historical test periods necessarily rely upon
15 actual, recorded financial data that is at least several months old at the time of rate
16 hearings and may include data at the beginning of the period that is up to two years old
17 by the time a final order is issued. Advocates of the projected test period approach
18 claim that a significant benefit associated with the use of budgeted future financial
19 data is the ability to reduce regulatory lag by relying upon data that is more
20 representative of the cost and revenue environment expected while the new rates
21 would be effective. However, even the recent actual and estimated data used in

⁵ The Commission has broad powers to award interim relief “when it deems it justified.” *WUTC v. Verizon Northwest, Inc.*, UT-040788, Order No. 11, ¶21 (footnote omitted). The *Verizon* order lists the 20 orders over the last three-plus decades in which the Commission has responded to such requests. *Id.*, n. 10.

1 assembling projected test period revenue requirement calculations must be fixed at a
2 point in time for presentation before the Commission and is therefore subject to
3 regulatory lag and the financial circumstances faced by the utility continue to change.

4 Regulatory lag is therefore an unavoidable characteristic of test period
5 regulation that can work to the advantage or disadvantage of the utility – depending
6 upon how future actual revenue and cost trends compare to amounts used to determine
7 the revenue requirement. Symmetrical risks and opportunities arise for utility
8 ratepayers and shareholders as a result of regulatory lag because favorable and
9 unfavorable changes in revenue requirement can produce over or under-earning
10 outcomes until either the utility or some other party initiates a new rate case
11 proceeding.

12 **Q. Are any regulatory incentives created by the existence of regulatory lag?**

13 A. Yes. As discussed above, one obvious and desirable incentive created by regulatory
14 lag is that management is encouraged to control and minimize operating expenses and
15 capital expenditures at economically efficient levels so as to optimize achieved
16 earnings between rate cases. Additionally, management faces an incentive to attempt
17 revisions to the traditional regulatory framework, either through legislative initiatives
18 or regulatory proceedings, in an effort to change the methods and procedures through
19 which cost of service changes can be translated into increased revenues. The new
20 tracking tariffs for depreciation cost increases and for gas usage per customer that are
21 proposed by Puget are examples of efforts to “sweeten” the regulatory framework

1 with preferential ratemaking treatment for isolated elements of the overall revenue
2 requirement calculation.

3 **Q. How does the creation of rate tracking tariffs, such the proposed new**
4 **depreciation expense tracking and GRNA customer usage tracking, impact**
5 **regulatory lag and the incentive to utility management that is created by**
6 **regulatory lag?**

7 A. Tracking tariffs can virtually eliminate the regulatory lag incentive. PSE's
8 depreciation tracker, if approved, would reduce the incentive faced by management to
9 carefully manage capital expenditure levels between rate case test years, because any
10 increases in depreciation expense caused by transmission and distribution (T&D)
11 capital spending can be translated into rate increases outside of a formal rate case
12 proceeding. On the other hand, with respect to the GRNA proposal, PSE has little
13 influence over gas usage per customer volumes because most of such fluctuation
14 between rate cases is caused by weather variation and by customer usage impacts
15 caused by appliance efficiency improvements, price elasticity and other externalities.
16 I discuss gas usage incentive concerns in a later section of my testimony.⁶

17 **IV. EXPANDED RATE TRACKING SHIFTS RISKS AND COSTS TO**
18 **RATEPAYERS**

19 **Q. How would Commission approval of Puget's proposed depreciation expense**
20 **tracking tariff impact customers?**

21 A. Puget's proposal represents higher prices for consumers with no corresponding

⁶ See pp. 40-42.

1 demonstrated benefits. In its proposed form, PSE's proposed Depreciation Tracker
2 would immediately increase rates by \$7.9 million for electric customers and by \$10.9
3 million for gas customers.⁷ Then, in subsequent years, additional rate increases would
4 occur for further increases in depreciation expense using the form of calculations
5 presented in Mr. Story's testimony at pages 74 and 75. Notably, there is no guarantee
6 that PSE will delay filings for traditional rate increases in the future, even if the
7 proposed tracker is approved.

8 **Q. How would Commission approval of Puget's proposed GRNA decoupling**
9 **tracking tariff impact customers?**

10 A. Again the Company's proposal promises higher prices paid by consumers, with no
11 guarantee that PSE will not seek traditional rate increases in the future or accept a
12 lower rate of return so as to recognize the shifting of sales volume risks to customers.
13 I will discuss in greater detail how the proposed GRNA would impact customers in a
14 later section of this testimony.

15 **Q. What do these two alternative ratemaking proposals have in common?**

16 A. Both of PSE's proposed new rate trackers represent management's selection of
17 isolated elements of the revenue requirement calculation, where future changes are
18 expected to have negative profit consequences, for piecemeal rate changes that would
19 shift costs and risks to ratepayers. These regulatory "sweeteners" would distort the
20 Washington regulatory framework and would systematically disadvantage ratepayers

⁷ Direct Testimony of John H. Story, Exhibit No. ____ (JHS-1T), p. 76.

1 who are entitled to a more balanced assessment of the overall cost of service when
2 utility rates are changed.

3 **Q. Has PSE made any showing that it will need the additional future revenues that**
4 **would be created through GRNA and Depreciation Tracker piecemeal rate**
5 **increases in order to have a reasonable opportunity to earn the allowed rate of**
6 **return?**

7 A. No showing has been made that any known and measurable changes in future PSE
8 revenues or expenses would contribute to significant earnings deficiencies that could
9 not be sufficiently addressed under traditional regulation. PSE does offer what it calls
10 “attrition” calculations based upon trending of historical expense levels, but does not
11 advocate direct utilization of the results.⁸ Other than speculation regarding possible
12 future PSE capital spending levels and internally developed financial forecasts, no
13 evidence of known and measurable financial changes has been presented.

14 **Q. If the Commission approves the GRNA and depreciation expense trackers, over**
15 **the objections of Public Counsel, will operating risks normally borne by**
16 **shareholders be shifted to ratepayers?**

17 A. Yes. The two new trackers, if approved, would substantially sweeten the regulatory
18 framework within which PSE conducts its business. Any future increases in
19 depreciation expense that would normally be borne by shareholders between rate case

⁸ Direct Testimony of John H. Story, Exhibit No. ____ (JHS-1T), pp. 62-66 and Exhibit Nos. ____ (JHS-11 and JHS-8). See also Direct Testimony of Karl R. Karzmar, Exhibit No. ____ (KRK-1T) at pp.36-41 and Exhibit Nos. ____ (KRK-6 and KRK-7).

1 test years, to be funded from reductions in other utility costs or from customer sales
2 gains, would instead be tracked through rate changes to be funded on a piecemeal
3 basis by ratepayers. Similarly, if normalized gas usage per customer declines
4 between test years, PSE would increase rates to shift such risk to its customers on a
5 piecemeal basis.

6 **Q. Has the Commission previously authorized rate tracking mechanisms that**
7 **benefit PSE shareholders, by shifting the risks arising from large and volatile**
8 **cost changes to ratepayers?**

9 A. Yes. PSE is already insulated from significant risks associated with changes in
10 volatile purchased energy costs through its Commission-approved PCA and PGA
11 mechanisms. Puget is over-reaching in this case, by seeking two new rate tracking
12 mechanisms to further transfer its operational risks onto ratepayers.

13 **Q. Would it be appropriate for the Commission to make a downward adjustment to**
14 **the authorized return on equity if revenue decoupling or the proposed**
15 **depreciation expense tracking tariff is approved in this Docket?**

16 A. Yes. The return on common equity that is allowed by the Commission is intended to
17 compensate for the financial and business risks that are borne by equity investors in
18 Puget Energy, Inc. stock. Commission approval of the depreciation expense tracking
19 and GRNA tariffs would directly and favorably impact PSE's future revenues and
20 income levels while reducing existing levels of operating risk arising from regulatory
21 lag. The allowed return on equity should therefore be commensurately lower with the

1 depreciation tracking and GRNA tariffs in place than is required without such
2 regulatory sweeteners.

3 **V. COMPLEXITY AND ADMINISTRATIVE BURDENS ARE INCREASED**
4 **BY TRACKING TARIFFS**

5
6 **Q. How do tracking tariffs impact regulatory complexity and administrative costs?**

7 A. The addition of tracking tariffs adds complexity to regulatory processes in several
8 ways. First, each new tracking tariff creates new regulatory reporting in support of
9 periodic price changes that must be created by utility company staff and then
10 reviewed by Commission personnel. Then, it may be necessary for Commission Staff
11 to organize and conduct audits of the underlying financial data beneath the filings,
12 since customer prices are directly impacted by such data. If any disputes arise from
13 either informal review procedures or more comprehensive audits, it may be necessary
14 to develop formal discovery and dispute resolution procedures. When applicable
15 review procedures are completed, the utility must implement the rate change along
16 with any customer disclosures that may be required and then be ready to respond to
17 customer inquiries arising from rate changes. Unfortunately, because tracking tariffs
18 are designed to facilitate expedited rate changes, the process just described must often
19 occur within a compressed timeline that can frustrate efforts and thorough review
20 and/or contribute to increased costs to the utility and the regulatory agency.

1 **Q. Is it reasonable to expect that PSE employees and WUTC Staff personnel would**
2 **be burdened with significant additional work if the GRNA were adopted?**

3 A. Yes. Mr. Amen's testimony and his Exhibit Nos. ____ (RJA-8) and (RJA-9) illustrate
4 and describe the monthly deferral calculations for a single month and provide details
5 of the proposed GRNA tariff, indicating considerable effort would be involved in
6 collecting and assembling supporting information and performing calculations to
7 derive and implement GRNA rate changes. Given the importance of the calculations
8 to customers' rates, WUTC Staff personnel would need to be tasked to review and
9 audit such calculations. In Public Counsel Data Request No. PC-047, the Company
10 was asked for its "best estimate of annual administrative and regulatory costs to be
11 incurred if the GRNA decoupling mechanism is approved by the Commission and
12 implemented by Puget." Objecting that the question "is speculative," the Company
13 then responded that the additional impact on PSE would be "minimal" and that while
14 it was "not in a position to estimate the amount of WUTC Staff time" that would be
15 involved, it did not anticipate it would be "unduly burdensome."

16 I do not agree with this assessment. Even if not readily determined at this
17 time, any regulatory complexity and burden added by the GRNA would be additive to
18 the regulatory administrative burden and costs already arising from the Company's
19 PGA and PCA. It would certainly not be "minimal" if significant disputes arise over
20 implementation details.

1 **Q. Would PSE’s proposed Depreciation Tracker, if approved, also add to the**
2 **cumulative administrative burden upon the utility and the WUTC Staff?**

3 **A. Yes, for the same reasons discussed above with respect to the GRNA.**

4 **VI. REBUTTAL TO PUGET’S DEPRECIATION TRACKER WITNESS**

5 **Q. Beginning at page 57 of his testimony, Mr. Story describes regulatory lag and**
6 **attrition, which he says, “...can occur if an historical test year is used for setting**
7 **rates for a company that is experiencing considerable growth or replacement of**
8 **infrastructure and its marginal cost of serving customers is greater than its**
9 **embedded cost of serving customers.” Do you agree with these general**
10 **observations?**

11 **A. I agree that actual returns earned by a regulated utility will depart from authorized**
12 **return levels, depending upon whether costs (expenses and depreciable net**
13 **investment) grow more rapidly than revenues. However, utilities that are**
14 **experiencing considerable growth do not necessarily face earnings attrition. If growth**
15 **is causing attrition, there may be problems with main and/or service line extension**
16 **policies or with rate design. Absent these problems, customer growth is normally**
17 **accretive to earnings by adding margin contribution to help the utility recover its**
18 **significant fixed costs, including the overheads of the business.**

19 **With respect to the Depreciation Tracker proposal, PSE argues that it may**
20 **suffer future “attrition” because of the use of an historical test period while it is**

1 experiencing considerable growth or replacement of infrastructure.⁹ Mr. Story's
2 attrition concern arising from "replacement of infrastructure" is intuitively appealing,
3 but is not supported by any empirical analysis in the Company's filing. Utility
4 companies are continuously replacing portions of the embedded investment in utility
5 plant in service, by retiring "old" plant and installing "new" plant at generally much
6 higher current replacement prices. Some of this continuing investment is needed to
7 extend facilities to new customers or to expand the capacity of gas and electric
8 facilities, while other plant investment may be triggered by excessive gas leaks or
9 outage response costs arising from substandard existing electric or gas facilities.
10 Other categories of investment include replacement of facilities that are simply worn
11 out and no longer fully functional, relocation of facilities for public improvements,
12 replacement of assets that are more costly to maintain than replace, compliance with
13 regulatory mandates or installation of new automation technologies that promise
14 operational efficiencies. If "infrastructure replacement" were the systemic attrition
15 problem that Mr. Story suggests, every energy utility in the country would need
16 annual rate increases to contend with the generally higher replacements costs for
17 retired plant assets. Obviously many other factors, including productivity effects
18 (which can be difficult to isolate) also influence utility revenue requirements, in ways
19 that serve to mitigate such inflationary pressures.

⁹ Direct Testimony of John H. Story, Exhibit No. ____ (JHS-1T), pp. 57 and 63-66.

1 **Q. At page 64 of his direct testimony, Mr. Story references “an attrition**
2 **adjustment in this case based on the trended methodology that the Commission**
3 **has accepted in some historic rate cases.” In your opinion, should the**
4 **Commission rely upon the electric or gas “attrition analysis” that is sponsored**
5 **by Mr. Story (electric operations) or Mr. Karzmar (gas operations) to quantify**
6 **any additional regulatory relief for PSE?**

7 A. No. Trending of historical accounting data does not produce reliable estimates of
8 changes in future revenues or cost levels that would help to define future revenue
9 requirements or needed attrition allowances. If ratemaking were this simple,
10 regulators could have two rate case proceedings for each utility they regulate,
11 compare how costs and revenues changed between the two test years, and then
12 extrapolate the rates of change to prescribe utility rates for many future years (and
13 then retire). Notably, PSE does not use this trending approach to develop its own
14 internal management financial forecasts of future revenues, costs and operating
15 income.¹⁰ Most telling is the fact that PSE has not advocated use by the Commission
16 of results from the trending calculations it has performed.

17 **Q. At page 63 of his direct testimony, Mr. Story states, “The Company is proposing**
18 **a new Depreciation Tracker that would true up revenues for changes in**
19 **depreciation expense related to natural gas and electric transmission and**
20 **distribution (“T&D”) capital investment, which I describe in greater detail**

¹⁰ Direct Testimony of John H. Story, Exhibit No. ____ (JHS-1T), p. 65. Comparisons between a trending-based attrition allowance for gas operations and the quite different results from internal management forecasts for gas operations are discussed by Mr. Karzmar at Exhibit No. ____ (KRK-1T), p. 39.

1 **below.” Should a Depreciation Tracker for changes in T&D depreciation**
2 **expense be approved for PSE?**

3 A. No. Such a rate tracker would be distortive of test period relationships. Some of the
4 new electric and gas distribution plant investment that PSE would like to include in
5 the proposed new depreciation tracker to increase customer rates on a volumetric
6 basis would relate to new plant investment made to connect new customers.
7 However, revenues and margins earned by PSE from serving new customers between
8 rate case test years are retained for shareholders, because there is no existing or
9 proposed tracking tariff that would reduce gas and electric prices to account for such
10 margin growth. Raising the rates payable by all customers through a tracker for
11 depreciation increases on plant investment made to serve new customers is blatantly
12 unfair, because there is no proposed tracker accounting for the incremental profit
13 margins earned from sales to the new customers. The mechanics of the tracker
14 calculation would only indirectly account for load growth by dividing depreciation
15 expense by total volumetric throughput that increases through time,¹¹ but this
16 approach does not accurately account for additional margin income PSE will actually
17 collect from new customers that will be available to help “pay for” increased
18 depreciation and other cost changes.

¹¹ *Id.* p. 74. In the example Depreciation Tracker calculation tables, “Delivered Load (MWH)” and “Delivered Load (thousand therm)” are allowed to increase from test year levels to estimated 2007 levels.

1 **Q. Would Commission approval of Puget’s proposed depreciation expense tracking**
2 **tariff disturb the existing regulatory lag incentives associated with capital**
3 **expenditures?**

4 A. Yes. If changes in depreciation expense are tracked into piecemeal rate increases
5 between rate cases, the incentive that would normally exist to carefully control
6 incurred costs for capital expenditures would be blunted. With such a tariff in place,
7 Puget management could, and probably should, focus more attention upon other
8 business issues and care less about stringent cost controls over capital expenditures
9 that can simply be tracked into higher depreciation tracker rate levels charged to
10 customers. In fact, the preferential regulatory treatment that Puget now proposes for
11 depreciation on certain capital additions may introduce a bias into otherwise balanced
12 economic analyses of specific capital projects that promise operational savings. For
13 example, if Puget could invest more capital in its gas distribution plant to reduce its
14 leak response expenses below levels that are built into rate case revenue
15 requirements, depreciation on the capital invested would translate into piecemeal rate
16 increases, while the favorable change in operations and maintenance (O&M) would
17 be retained solely for shareholder benefit until leak response expenses were reviewed
18 and updated in the next rate case test period. This is an example of an input mix bias
19 problem that can arise from inconsistent regulatory treatment of selective elements of
20 the revenue requirement – where certain resource inputs to the business (in this
21 example capital investment) are afforded preferential regulatory treatment in relation
22 to alternative input costs (expenses associated with leak response service calls).

1 While gas leaks should be minimized for both economic and public safety reasons,
2 the introduction of disparate regulatory treatments may lead to sub-optimal decisions
3 by management in evaluating specific gas distribution plant replacement projects
4 where the cost/benefit relationship is questionable.

5 **Q. Is it possible for new future investment in T&D plant to create operational**
6 **efficiencies that reduce expenses from the levels included in test year revenue**
7 **requirement calculations?**

8 A. Yes. Many types of O&M expenses are influenced by the age and condition of utility
9 plant. As noted above, service calls for gas leaks and gas leak repair expenses are
10 impacted by the condition of mains and service lines and the systematic replacement
11 of problem areas in the gas distribution system can produce profound improvement
12 (i.e., reductions) in these costs. In the electric business, the replacement, relocation or
13 undergrounding of distribution facilities can save on outage restoration as well as
14 tree/brush forestry management costs. Automation opportunities exist through
15 modernization of T&D facilities, with examples such as automated meter reading and
16 substation automation, where staffing and O&M expenses may be avoided through
17 new capital investments.

18 The “infrastructure investments” that Mr. Story claims are contributing to
19 “financial pressures” for the Company¹² actually represent capital expenditures that
20 are aimed at efficiently serving new and existing customers, growing margin revenues
21 and controlling expense levels. Therefore, depreciation expense on T&D investments

¹² *Id.* p. 78, l. 1.

1 should not be subject to single issue rate tracking unless all of the corresponding
2 operational impacts of such tracking are also recognized within the tracker. However,
3 as a practical matter, it would likely be impossible to design a comprehensive
4 tracking mechanism to capture all financial impacts arising from new capital
5 investment, because of the capital intensity of the utility business and the complex
6 ways in which changes in utility plant assets impact business operations.

7 **Q. Would the financial impact of tracking changes in electric and gas T&D**
8 **depreciation expense be substantial enough to have a material impact upon**
9 **revenue requirements and the financial performance of the business between**
10 **rate cases?**

11 A. No. In the back-casting analysis performed by PSE, the annual financial impacts of
12 the proposed Depreciation Tracker, if it had been in effect in the years 2003 through
13 2005, would have ranged from \$3.1 to \$5.9 million per year. When these annual
14 amounts are reduced for income taxes at the 35 percent statutory Federal rate, these
15 amounts represent no more than 2.5 percent of Puget Energy's reported 2005
16 consolidated net income.¹³

17 **Q. Should increases in T&D depreciation expense be viewed as entirely beyond the**
18 **control of management?**

19 A. No. While it is true that significant capital investment is continuously required by
20 utilities to replace, extend and modernize electric and gas T&D facilities,

¹³ Puget Energy, Inc. 2005 Annual Report, page 2 shows 2005 Consolidated Net Income of \$155.7 million. \$5.9 million times (1-35%) / 155.7 = 2.5%.

1 management has considerable discretion and control over capital expenditure timing
2 and cost levels and should be actively involved in facilities planning and design,
3 construction workforce management, materials procurement, contractor bidding and
4 administration and other elements of capital expenditure optimization.

5 **Q. Can the input values and computations involved in administering the**
6 **Company's proposed Depreciation Tracker tariff be readily audited and verified**
7 **through expedited regulatory reviews?**

8 A. No. The primary input values are calculations of annual depreciation expense which
9 result from application of approved depreciation accrual rates to all of the balances
10 within PSE's gas and electric T&D utility plant accounts. While a cursory review of
11 depreciation expense accruals and the resulting tariff rate calculations would not by
12 itself be burdensome, ignoring the GRNA proposal of PSE and other utilities'
13 potential future tracker proposals, any intensive review of changes in the underlying
14 Plant in Service accounts that drive depreciation expense would not, in my opinion,
15 be possible as part of an expedited review. Plant in Service balances represent the
16 cumulative accounting for all of the construction work orders that support plant
17 additions and retirements occurring throughout the year, representing a significant
18 audit effort if such balances needed to be thoroughly analyzed before being allowed
19 to impact utility rates. In a rate case, the Staff and intervenors have an opportunity to
20 scrutinize new utility plant additions and retirements that have occurred since the
21 prior case test year, and then more rigorously test and verify the depreciation accruals

1 that result from changes in Plant in Service.

2 **VII. REBUTTAL TO PUGET’S GAS REVENUE NORMALIZATION**
3 **ADJUSTMENT (GRNA) WITNESS**

4
5 **Q. At pages 27 through 38 of his testimony, Mr. Amen describes several concerns**
6 **he has with traditional ratemaking for gas utilities, including annual variations**
7 **in actual sales volumes and margins due to weather fluctuations, declining gas**
8 **consumption per customer due to conservation effects, and the corresponding**
9 **financial impacts felt by PSE. In your opinion, are these new concerns that**
10 **require dramatically changed regulatory approaches?**

11 **A.** No, these are not new concerns. Gas distribution utilities have always been subject to
12 the sales impact of weather variation around “normal” degree day levels, which in
13 some years causes significant gas margin (revenues less purchased gas cost) variances
14 above or below intended levels. However, over multiple years, the effects of actual
15 heating season weather conditions will tend to average out near the normalized level
16 used to set gas utility delivery rates. Mr. Amen has not demonstrated any changed
17 circumstances in weather trends or impacts upon PSE that now justify modification of
18 the Commission’s long standing regulatory approach to balanced test year regulation
19 based upon normalized weather conditions.

20 The more gradual conservation trend reducing PSE’s gas usage per
21 customer is also not a new phenomenon, because consumers have been replacing less
22 efficient furnaces and other appliances and building tighter, more efficient houses for
23 many years. Indeed, Mr. Amen states at page 33 of his direct testimony, “The yearly

1 decline in residential use per customer has averaged approximately 1.2% since 1994
2 on a weather-adjusted basis and PSE expects this trend to continue into the future”.
3 No dramatically changed facts or circumstances now support elimination of normal
4 test year ratemaking that sets gas delivery rates based upon then-current normal
5 weather sales volumes, allowing productivity gains elsewhere in the business to offset
6 the gradual effects of changing sales volumes.

7 **Q. Should the Commission approve PSE’s proposed GRNA tariff because of**
8 **weather effects upon customer usage or because of conservation effects?**

9 A. No. Gas utility delivery revenues (revenues less gas costs) are subject to fluctuation
10 for several reasons, including sales volume variation due to weather, variation due to
11 conservation and price elasticity effects as well as growth in revenue from adding
12 new customers. Puget’s GRNA proposal would adjust rates to eliminate gas usage
13 and revenue fluctuations due to weather or conservation effects, effectively
14 guaranteeing collection by the utility of the gas margin revenue per customer that was
15 used to set rates.¹⁴ At the same time, PSE would be allowed to collect and retain for
16 its shareholders (not track through rates) steadily increasing margin revenues
17 associated with adding new customers. The combined effect of rate tracking for
18 anticipated declines in usage per customer, while not tracking favorable revenue
19 impacts from adding customers, will assure the utility and its shareholders of stable

¹⁴ The proposed GRNA would guarantee PSE recovery of the gas sales margin “per customer” that was established in the rate case by tracking changes from these values and adjusting future rates. While these changes are labeled “conservation” in Mr. Amen’s testimony, they also include all customer demand response to changes in pricing of natural gas (elasticity effects) that occur through purchased gas adjustments.

1 and increasing future revenue levels while shifting all risks associated with usage per
2 customer declines due to weather and conservation onto customers. Customers would
3 pay higher rates as a result of their collective success in reducing usage and would
4 pay higher rates when weather is mild, while paying lower rates only when sales
5 growth due to severe winter weather is normalized through the GRNA. All of this
6 would occur while PSE gas margin revenues continue to grow as customers are added
7 to the system.

8 **Q. At page 33, Mr. Amen poses the question, “Historically, has PSE experienced a**
9 **decline in gas use per customer” and then answers, “Yes” with reference to his**
10 **Exhibit No. ____ (RJA-4). What is the significance of this presentation of “per**
11 **customer” statistical information?**

12 **A.** On a “per customer” basis, PSE gas delivery volumes are declining, while on a total
13 basis, such volumes are not declining. Total sales volumes are the product of the total
14 number of customers being served as well as the usage “per customer” in any given
15 year. Mr. Amen’s testimony is silent with regard to total delivery volume trends or
16 the number of customers being served, instead focusing upon the usage “per
17 customer” data where he can show declines and then argue for exceptional
18 ratemaking remedies.

1 **Q. Have PSE total gas delivery volumes changed much in the past few years as a**
2 **result of conservation by customers, as suggested by the Company's GRNA**
3 **testimony?**

4 A. No. According to information contained in the Puget Energy 2005 Annual Report,
5 actual gas volumes delivered in the past five years have been relatively stable, in spite
6 of milder than normal weather in each of the three most recent years:

Year	Therms (millions)	% Colder/(Warmer) Than Average
2001	1039	4%
2002	1047	3%
2003	1025	-6%
2004	1010	-8%
2005	1034	-6%

13 Source: 2005 Puget Energy Annual Report to Shareholders, pages 138 and 139.

14 **Q. If we look at financial impacts, has PSE actually experienced declining gas**
15 **margins in recent years, as implied by the testimony of Mr. Amen that discusses**
16 **weather variability upon sales and generally declining usage due to**
17 **conservation?**

18 A. No. Mr. Amen is careful in his testimony to discuss usage "per customer", rather
19 than overall volume and margin revenue data. The reality is that PSE gas margin
20 revenues are growing as a result of adding customers and raising rates through
21 traditional rate cases. According to information reported by Puget in its Gas
22 Commission Basis Reports, gas margin revenues from Sales to Customers (less

1 purchased energy costs) have actually grown from \$230 million in 1997¹⁵ to about
2 \$336 million in the period ended September 2005,¹⁶ an increase of more than \$100
3 million. In this time period, one rate reduction (a one percent revenue decrease in
4 WUTC Docket Nos. UE-951270 and UE-960278) and two rate increases were
5 approved by the Commission. The two rate increases, in Docket Nos. UG-011571 and
6 UG-040460, increased annual margin revenues by \$34.3 million in September 2002
7 and by \$25.3 million in March 2005.¹⁷

8 **Q. Would Mr. Amen's proposed GRNA tariff account fully decouple changes in**
9 **sales volumes from the margin revenues that PSE would collect in the future?**

10 A. No. PSE does not want to completely decouple sales volumes, but instead wants to
11 retain for shareholders (by not tracking) the favorable effects of sales growth caused
12 by adding new customers, while increasing utility rates for changes in usage on a "per
13 customer" basis. This selective decoupling effect can be seen within Mr. Amen's
14 Exhibit No. ____ (RJA-8), which shows an Example of Monthly Deferral Calculation if
15 the GRNA is approved. These calculations illustrate how the Company proposes to
16 keep for its shareholders, as an addition to "Base Line Margin", all of the revenues
17 associated with its calculated "Customer Growth Adjustment".¹⁸ By adding more
18 "Base Line Margin" to the amounts against which actual margin revenue is tracked,
19 the Company ensures that its future revenues will not just be stabilized, but will grow
20 directly in proportion to added new customers.

¹⁵ Response to WUTC Data Request No. 136; Dec 1997 \$409M revenue, less \$179 purchased energy.

¹⁶ *Id.* \$879M revenue, less \$540M purchased energy.

¹⁷ Response to Public Counsel Data Request No. 66.

¹⁸ See ll. 1-11 of Exhibit No. ____ (RJA-8).

1 It is quite possible to design a full decoupling mechanism that would
2 guarantee ultimate recovery of a fixed dollar amount of total margin revenue, but the
3 proposed GRNA does much more than this. Puget’s proposed GRNA would not
4 stabilize and decouple margin revenues at a Commission-authorized fixed dollar
5 level, but would instead amplify future revenue growth by increasing delivery prices
6 for conservation effects on “per customer” sales, while letting PSE retain all revenue
7 growth that is caused by adding new customers. In the Company’s confidential
8 response to Public Counsel Data Request No. 44, simulation calculations for the
9 proposed GRNA mechanism confirm that PSE intends to retain significant ongoing
10 margin revenue growth from new customers for its shareholders, while also
11 increasing rates through the GRNA mechanism to track anticipated further declines in
12 usage per customer.¹⁹

13 **Q. If we look backwards, instead of forward, how much higher would PSE’s actual**
14 **growth in gas margin revenues have been in the past five calendar years if the**
15 **Company’s proposed GRNA decoupling rates had been effective for gas utility**
16 **operations?**

17 A. According to the Company’s response to Public Counsel Data Request No. PC-045,
18 the Company would have collected positive additional revenues through the GRNA
19 in every year, above and beyond the historically favorable actual margin trends

¹⁹ The projected “Customer Growth Adjustment” in PSE’s Response to PC DR No. 44 indicates anticipated residential margin revenue increases of about **Confidential Begins** ***** **[Confidential Ends]** per year along with commercial/industrial customer growth of about **[Confidential Begins]** ***** **[Confidential Ends]** per year.

1 mentioned above, by the following amounts:

Year	GRNA Revenues
2001	\$7,110,931
2002	\$1,843,666
2003	\$1,882,868
2004	\$9,750,213
2005	\$9,533,081

2

3 Source: Attachment A to PSE's Response to Public Counsel Data Request PC-045.

4 The consistently positive revenue amounts indicate how the proposed
5 GRNA would favor shareholders, by charging customers higher rates to make up for
6 declining usage per customer, while ignoring the fact that margin revenues in total are
7 growing due to customer growth.

8 **Q. Does traditional ratemaking involve the measurement of overall gas delivery**
9 **volumes, in a manner that recognizes both the number of customers being**
10 **served, as well as the recently declining usage "per customer" that Mr. Amen**
11 **has chosen to focus upon?**

12 A. Yes. This holistic test year approach under traditional regulation is critically
13 important to the establishment of just and reasonable utility rates, because it accounts
14 for all of the elements of the revenue requirement, including the number of customers
15 being served in the test year, their usage levels, and all of the investment and
16 expenses incurred to provide gas delivery services to such customers within the test
17 year. The reasonableness of resulting utility rates is heavily dependent upon a

1 balanced review of all ratemaking elements at a common point in time. Departures
2 from the traditionally balanced test year approach should only be implemented when
3 compelling facts justify upsetting this balance by establishing special cost trackers or
4 accounting deferrals subject to strictly applied regulatory criteria.

5 **Q. PSE may argue that, because the Company incurs additional investment and**
6 **expenses when it connects and serves new customers, the Commission should**
7 **ignore the increasing gas delivery levels and revenues caused by adding new**
8 **customers and adopt rate tracking for only declining usage “per customer”.**
9 **Would this be reasonable?**

10 A. No. As noted in my prior response, traditional regulation involves an intensive
11 review of all of the elements of the revenue requirement within the established test
12 year, including all costs associated with adding and serving new customers. It would
13 be inappropriate to assume that PSE realizes no financial benefit from customer
14 growth between rate cases that can help to mitigate conservation effects. It would
15 also be inappropriate, in my view, to assume that PSE is unable to deploy new
16 technology or improved methods of operation to exploit productivity gains useful in
17 mitigating cost increases or ratepayer conservation effects.²⁰ I would encourage the

²⁰ In its response to Public Counsel Data Request No. 39, PSE states, “The prefiled direct testimony of many of PSE’s witnesses in this proceeding identify a variety of technological innovations, efficiency measures and best practices that PSE has undertaken over the past several years to improve productivity and reduce the cost associated with providing regulated utility services in Washington, including, for example, the prefiled direct testimonies of: Kimberly J. Harris, Exhibit No. ____ (KJH-1T), Susan McLain, Exhibit No. ____ (SML-1CT); Eric M. Markell, Exhibit No. ____ (EMM - 1CT); Roger Garratt, Exhibit No. ____ (RG-1HCT); David E. Mills, Exhibit No. ____ (DEM- 1CT); Bertrand A. Valdman, Exhibit No. ____ (BAV-1CT); Donald E. Gaines, Exhibit No. ____ (DEG-1CT); and Tom M. Hunt, Exhibit No. ____ (TMH-1T).”

1 Commission to not accept any unproven assumptions regarding whether or not
2 customers added to PSE's gas delivery system between rate cases are financially
3 harmful or beneficial to the Company.

4 **Q. In a previous section of your testimony you described the incentives created by**
5 **regulatory lag. Has PSE proposed the new GRNA tariff out of concern that**
6 **regulatory lag may work against the interests of shareholders in the future**
7 **without such tracking?**

8 A. Yes. With respect to the GRNA, Mr. Amen states at page 27 that PSE is proposing
9 this ratemaking mechanism for "three important and interrelated reasons". He then
10 describes concerns with accurate forecasting of gas volumes that will be used by
11 customers in future periods, with declining future gas volumes due to energy
12 efficiency programs for customers, and with the impact of weather on PSE's financial
13 condition. In subsequent testimony, Mr. Amen explains that sales volume
14 fluctuations due to weather cause earnings variability,²¹ while a declining long-term
15 trend in weather-adjusted usage per customer is also discernable due to
16 conservation.²²

17 The weather impact upon actual sales volumes in any given year can be
18 significant, but over many years sales will tend to gravitate toward average or
19 "normal" levels. On the other hand, any longer term conservation trends expose the
20 Company to regulatory lag between rate cases, when declining usage revenues due to

²¹ Direct Testimony of Ronald J. Amen, Exhibit No. ____ (RJA-T1, pp. 30-32 and 36-37) and Exhibit No. ____ (RJA-4).

²² *Id.* p. 33 and Exhibit No. ____ (RJA-5).

1 conservation effects cannot be readily translated into rate increases under traditional
2 ratemaking methods. Any ongoing conservation effects among existing customers
3 may very well be offset by productivity gains that reduce expenses or with new
4 revenues from added customers that are not accounted for in the proposed GRNA.

5 **Q. In your opinion, is the expected financial impact of PSE gas customer**
6 **conservation and weather fluctuation substantial enough to have a material**
7 **impact upon revenue requirements and the financial performance of the**
8 **business between rate cases?**

9 A. No. In the back-casting analysis performed by PSE, the annual financial impacts of
10 the GRNA if applicable in 2001 through 2005 would not have exceeded \$10 million
11 in any year. When reduced for income taxes at the 35 percent statutory Federal rate,
12 these amounts represent about 4 percent of Puget Energy's reported 2005
13 consolidated net income.

14 **Q. In a previous section of testimony, you described the incentives created by**
15 **regulatory lag. Does regulatory lag serve to discourage utility management from**
16 **actively promoting conservation of energy?**

17 A. Not significantly. Utility shareholders will generally benefit when sales volumes
18 increase between test periods and are harmed when sales decline. Sales volumes are
19 influenced by the addition of new customers and by changes in usage levels of
20 existing customers, suggesting that utility promotion of energy conservation by
21 existing customers might be actively discouraged by management. However, in this
22 era of high-priced natural gas, conservation measures are necessary to attract new

1 customers and to retain existing gas utility customers that may otherwise elect
2 alternative energy sources such as electricity when appliances are being installed or
3 replaced. PSE has little choice in this environment but to promote the efficient use of
4 natural gas.

5 As noted at page 33 of Mr. Amen's direct testimony, "PSE's customers
6 have reduced their gas consumption, not unlike other gas customers through the U.S.
7 [footnote omitted], primarily by the use of increased efficiency gas appliances and
8 tighter, more energy efficient homes as a result of improved insulation and window
9 products and higher building code standards." Clearly, conservation in gas usage is a
10 long-term phenomenon, driven by replacement of gas burning appliances with ever
11 more efficient newer technology as well as consumer demand response to higher
12 commodity prices. The Commission should, in my opinion, expect PSE to provide
13 energy conservation programs for its customers as a necessary element of its public
14 service obligation.

15 **Q. If the Commission is concerned about the potential disincentive to utility**
16 **management to promote reduced gas consumption between rate cases, are there**
17 **alternatives to the GRNA decoupling approach that can be employed?**

18 A. Yes. Regulators have responded to such "disincentive" concerns in the design of
19 utility demand side management ("DSM") programs by approving shareholder
20 incentives or compensation for DSM-caused lost margins within such programs. By
21 carefully targeting such incentives, it is possible to match the additional compensation
22 to shareholders to actual achievements under DSM measures that are deployed, rather

1 than globally shifting all risks associated with sales declines from shareholders to
2 customers.

3 **Q. Would a properly targeted regulatory incentive to fully compensate**
4 **shareholders for only the margin dollars actually lost to utility conservation**
5 **programs need to be scoped as broadly as the GRNA mechanism proposed by**
6 **PSE?**

7 A. No. The GRNA provides compensatory rate increases for all experienced usage per
8 customer reductions, whether the reductions are caused by utility conservation
9 programs, routine replacement of older appliances, turnover in housing stock with
10 more efficient designs or simple price elasticity demand responses of consumers. In
11 fact, utility sponsored conservation programs appear to produce only a modest impact
12 on anticipated sales volumes and margin revenues. In its response to NWECA Data
13 Request No. 033, PSE stated that, "...a gas energy efficiency stretch goal of 4.2
14 million therms was set for 2006 and 2007 in collaboration with the Conservation
15 Resources Advisory Group." Even if we assume that PSE achieved all of its "stretch"
16 goals through conservation programs over these two years, the resulting 2.1 million
17 annual therms of conservation demand reduction is only about 0.2 percent of PSE's
18 annual sales that exceed 1 billion therms. Such a small impact upon annual sales
19 from utility sponsored conservation efforts is insufficient cause to introduce a
20 complex new rate tracker that addresses all variations in usage per customer, most of
21 which variation is likely caused by other factors including weather, price elasticity
22 and continuing turnover of old appliances and housing.

1 **Q. Can the input values and computations involved in administering the**
2 **Company’s proposed GRNA tariff be readily audited and verified through**
3 **expedited regulatory reviews?**

4 A. Probably not. In his Exhibit No.__(RJA-8), Mr. Amen outlines the monthly
5 calculations involved in calculating current accounting deferrals associated with the
6 GRNA. The Company’s proposed tariff (Exhibit No. ____RJA-9) for the GRNA adds
7 considerable complexity to these monthly calculations by adding monthly accrued
8 interest to deferred balances for each of the applicable rate schedules and then
9 calculating the “Rate” to be charged by reference to tables of usage (Section 5) and
10 meter count (Section 6) values shown in the tariff. For these calculations to be
11 readily audited on an expedited basis, Staff and other concerned parties would need to
12 dedicate significant resources to the analysis of cumulative deferrals, the annual re-
13 determination of this rate and the required true-up of prior year over or under-
14 recoveries.

15 **Q. Please summarize your specific recommendations regarding PSE’s proposed**
16 **Depreciation Tracker and GRNA mechanism.**

17 A. For all of the reasons explained in my testimony, I recommend the Commission reject
18 PSE’s proposed Depreciation Tracker and GRNA mechanism.

19 **Q. Does this conclude your testimony at this time?**

20 A. Yes.

BEFORE THE WASHINGTON UTILITIES & TRANSPORTATION COMMISSION

WUTC V. PSE

DOCKET NOS. UE-060266 AND UG-060267

CROSS-ANSWERING TESTIMONY OF MICHAEL L. BROSCHE (MLB-4T)

ON BEHALF OF

PUBLIC COUNSEL

DATED AUGUST 23, 2006

1 **Q. Please state your name and business address.**

2 A. My name is Michael L. Brosch. My business address is 740 North Blue Parkway,
3 Suite 204, Lee's Summit, Missouri 64086.

4 **Q. Are you the same Michael L. Brosch who submitted Direct Testimony**
5 **identified as Exhibit No. __ (MLB-1TC) in this matter on behalf of Public**
6 **Counsel?**

7 A. Yes. My qualifications and previous utility regulation experience are described in
8 Exhibit No. ____ (MLB-1TC) and also within Exhibit Nos. ____ (MLB-2) and
9 (MLB-3).

10 **Q. What is the purpose of your Cross-Answering Testimony?**

11 A. My Cross-Answering Testimony is responsive to the Prefiled Direct Testimony of
12 Mr. Steven D. Weiss on behalf of the Northwest Energy Coalition (NWECC) and to
13 the Prefiled Direct Testimony of Commission Staff (Staff) witness Ms. Joelle
14 Steward on the topic of revenue decoupling. These two witnesses reject the specific
15 revenue decoupling proposal and tariff advanced by Puget Sound Energy (PSE), but
16 recommend alternative revenue decoupling approaches. These alternatives should
17 not be accepted by the Commission, for the reasons described herein and in my
18 Direct Testimony. I will not repeat the discussion in my Direct Testimony of the
19 many problems associated with usage per customer decoupling/tracking, but will
20 instead focus upon the details of the alternative proposals now being advocated by
21 Mr. Weiss and Ms. Steward.

1 **Q. At page 5 of his testimony, Mr. Weiss refers to “decoupling, or revenue cap**
2 **regulation” which he characterizes as “Breaking the link between the utility’s**
3 **commodity sales and the disincentive to run effective energy efficiency**
4 **programs or invest in or encourage other activities that may reduce load.”**
5 **Does the form of decoupling Mr. Weiss advocates impose any “revenue cap” or**
6 **fully “break the link” as his testimony implies?**

7 **A.** No. There is no revenue cap established or any “break in the link” accomplished by
8 the form of decoupling he recommends. Mr. Weiss has focused solely upon gas
9 usage per customer, ignoring the fact that total gas demand volume is a function of
10 both the number of customers being served and the average usage per customer.
11 PSE gas margin revenues are not subject to any “revenue cap” under an approach
12 that protects the utility against any continuing declines in usage per customer, while
13 allowing the utility to retain for shareholders all of the margin revenue growth
14 associated with customer growth. His proposal can actually be expected to amplify
15 future PSE margin revenue growth, by ensuring that customers added after the test
16 year produce revenue growth that is no longer offset by the gradually declining
17 usage per customer trend that has existed for many years. This problem with
18 tracking only usage per customer, rather than total usage volumes, was explained in
19 my Direct Testimony at pages 33-36.

20 **Q. Can the problem arising from a limited focus upon only usage per customer be**
21 **observed in the usage data summarized in Mr. Weiss’ testimony?**

1 A. Yes. At pages 12 and 13, residential sales volume graphs are presented by Mr.
2 Weiss on a “Therms/customer” basis, which imply that PSE gas sales volumes are
3 trending downward. In truth, PSE gas sales volumes are relatively stable and there
4 is no such downward trend, as I explained at page 34 of my Direct Testimony.

5 **Q. With respect to declining usage per customer that has been experienced**
6 **historically, if we ignore offsetting customer growth, do you agree with Mr.**
7 **Weiss regarding the causes for declining usage per customer?**

8 A. At page 13, Mr. Weiss states, “This reduction in residential usage is probably due to
9 a combination of factors: higher bills, more efficient appliances, and utility- and
10 customer-financed conservation investments. There are good reasons to believe this
11 trend will continue.” I agree that these are all factors impacting declining weather
12 normalized usage levels when evaluated on a per customer basis. Additional factors
13 include the improved building codes mentioned by Mr. Weiss at page 16 and
14 resulting trends in tightened building envelopes that contribute to declining usage
15 per customer.

16 An important distinction should be drawn at this point – most of these
17 drivers of declining usage per customer are beyond the control of the utility and are
18 therefore not influenced by the “incentives and disincentives embedded in
19 traditional utility regulation” that Mr. Weiss criticizes at pages 3 and 4 of his
20 testimony. For example, customer price elasticity effects flowing through the PGA
21 will occur without regard to the disincentives associated with traditional

1 ratemaking.¹ Similarly, the replacement of old appliances and furnaces with
2 modern and more efficient units will occur without regard to the scheme of utility
3 regulation that exists.² Unfortunately, Mr. Weiss recommends rate tracking for all
4 of this usage per customer variation from all of these causes (including weather) in
5 his decoupling recommendation. This causes his recommended regulatory remedy,
6 sales decoupling on a “usage per customer basis”, to be overly broad in relation to
7 the conservation disincentive problem he claims to be concerned about.

8 **Q. Does Mr. Weiss’ recommendation differ from the recommendation of**
9 **Commission Staff witness Ms. Steward with respect to how weather departures**
10 **from normal are treated?**

11 A. Yes. Mr. Weiss would allow rate recovery through decoupling for differences in
12 usage per customer caused by weather fluctuations above and below normal
13 conditions, where Staff’s proposal would not track weather fluctuations.³ There are
14 also differences between Mr. Weiss and Ms. Steward regarding other details of their
15 proposals involving the specific rate schedules to become subject to decoupling and
16 various incentives, capping and decoupling pilot program constraints.⁴

¹ In fact, price elasticity effects may be amplified somewhat by decoupling, if gas commodity price increases passed through the PGA cause customer demand reductions through thermostat dial-back or other conservation measures, which in turn contribute to decoupling price increases intended to “make up” for the margin losses from the price-driven lower sales.

² Federal appliance efficiency standards are mandated in 10 C.F. R. § 30.432. These standards have been increased in the past, such that older appliances being replaced today usually cannot be replaced without improving efficiency.

³ Exhibit No.__(SDW-1T), p. 7. Exhibit No.__(JRS-1T), p. 8. Notably, at page 21, Mr. Weiss states that NWECE would “support a more limited pilot” decoupling mechanism that does not include an adjustment for weather variability.

⁴ See generally Exhibit No.__(SDW-1T), at pp. 8-14 and Exhibit No.__(JRS-1T), at pp. 17-19.

1 **Q. Please summarize the individual drivers of changing PSE gas sales volumes**
2 **and explain whether each party's decoupling proposal would provide rate**
3 **recovery for those drivers.**

4 A. The following table sets forth the individually significant drivers of gas sales
5 volume changes and indicates whether gas usage changes caused by that variable
6 would be subject to rate recovery through the decoupling tariff proposal of each of
7 the parties:

8
9 Table 1: Rate Recovery of Sales Volume Drivers

SALES VOLUME DRIVER	GENERAL ONGOING SALES VOLUME IMPACT	PSE Decoupling Proposal	NWEC Decoupling Proposal	Staff Decoupling Proposal
Number of Customers	Increasing	No	No	No
Weather Abnormality	Variable	Yes	Yes	No
Price Elasticity	Decreasing	Yes	Yes	Yes
Replacement of Inefficient Old Appliances / Furnaces	Decreasing	Yes	Yes	Yes
Construction of Buildings – Improved Building Codes	Decreasing	Yes	Yes	Yes
Customer Financed Conservation Investments	Decreasing	Yes	Yes	Yes
Utility Sponsored Conservation Investments	Decreasing	Yes	Yes	Yes

10

1 This summary illustrates several important points. First, it shows (in the Number of
2 Customers line) that all of the decoupling proposals before the Commission in this
3 docket are imbalanced in favor of shareholders, because they would ignore
4 continuing growth in the number of customers being served. This customer growth
5 can be expected to continue to offset much or all of the last five listed sales volume
6 drivers that have had a negative impact upon sales volume trends.

7 Beyond this fundamental imbalance caused by excluding customer growth,
8 the summary table shows that most of the causes of sales declines that would be
9 tracked through decoupling have nothing to do with utility-sponsored conservation
10 programs that are thought to be subject to disincentives under traditional regulation.
11 For example, the summary shows that the decoupling recommendations of PSE,
12 Staff and NWECA would allow decoupling rate increases when customers adjust
13 thermostats or otherwise react to commodity price increases experienced through
14 the PGA. Additionally, the table shows that PSE would be allowed decoupling rate
15 increases between rate cases for sales volume declines caused by normal
16 replacement of old and inefficient appliances, furnaces and housing/buildings.
17 Further, if customers elect to invest in conservation retrofits at their own expense,
18 the decoupling proposals would allow PSE to increase rates to account for any
19 resulting sales declines caused by such customer-financed conservation. I believe
20 this table shows that decoupling, as proposed by PSE, Staff and NWECA, is an
21 unreasonably broad response to concerns about regulatory disincentives to utility-

1 sponsored conservation programs. Most of the drivers of sales volumes are not
2 sensitive to regulatory incentives to utility management.⁵

3 **Q. At page 9 of his testimony, Mr. Weiss states, “At a time of unprecedented**
4 **increases in gas and other energy costs, it is imperative that the Company be**
5 **allowed, and encouraged, to promote reduced energy usage.” How do you**
6 **respond?**

7 A. The table presented above is helpful in responding. First, it shows on the “Price
8 Elasticity” row that usage per customer declines caused by “unprecedented
9 increases in gas” prices would be tracked through the proposed decoupling
10 mechanisms. Utility management would probably claim that it has little or no
11 control over commodity prices, such that PGA recovery of price changes is
12 appropriate and necessary. Clearly, when faced by dramatically higher prices,
13 ratepayers can be expected to be motivated on their own to respond to those higher
14 prices, and management need not “be allowed, and encouraged” through a
15 decoupling mechanism to permit or allow ratepayers to respond to high prices. In
16 some respects, incentives to promote utility-sponsored conservation may be needed
17 less at times when consumers are painfully aware of high natural gas prices and can
18 be expected to dial back thermostats and independently employ conservation
19 measures. Notably, whenever ratepayers actually do respond to higher gas prices,
20 decoupling would effectively shift all risk of price elasticity demand response from

⁵ As discussed in my Direct Testimony, if PSE achieves its “stretch” conservation goal of 4.2 million therms for 2006-2007, the resulting 2.1 million annual therms of conservation demand reduction is only about 0.2 percent of PSE’s annual sales that exceed 1 billion therms. Exhibit No. ____ MLB-1TC at p.42.

1 shareholders to ratepayers between rate cases.

2 **Q. At page 10 of his testimony, Mr. Weiss states that “ambitious conservation**
3 **targets are a critical component of an effective conservation mechanism”.**
4 **How do conservation targets relate to usage per customer declines associated**
5 **with improved appliance efficiency or improved building codes?**

6 A. Much of the decline in average usage per customer is not related to company
7 conservation targets. Customers replace defective or obsolete appliances and
8 furnaces with modern, higher efficiency models for various reasons, not just
9 company programs or targets.⁶ Similarly, when building a new residence or
10 commercial building, improved construction standards and materials will be
11 employed and will cause more efficient energy consumption even if no
12 conservation targets have been imposed. The persistent gradual turnover of
13 housing/building stock and routine appliance replacement cycles explain much of
14 the declining trend in usage per customer that has occurred historically. There is no
15 need to adopt extraordinary regulatory measures such as decoupling rate trackers to
16 continue these historical conservation trends.

17 **Q. NWEA witness Mr. Weiss at page 16 and Staff witness Ms. Steward at page 14**
18 **propose adjustments to the PSE-proposed decoupling calculations for “new**
19 **customers”. Do these changes correct the problem associated with how**
20 **decoupling treats customer growth that you addressed in direct testimony?**

⁶ See footnote 2 regarding federal appliance efficiency standards.

1 A. No. Modifications in the treatment of new customers that are proposed by NWEC
2 and Staff represent only refinement of details about average per customer usage
3 assumptions⁷, while doing nothing to remedy the fundamental piecemeal ratemaking
4 problem that results from carving out revenue increases created by future customer
5 growth for retention by shareholders. As I mentioned in my Direct Testimony, all
6 elements of the revenue requirement calculation are dynamic through time and
7 changes that are favorable tend to offset other changes that are unfavorable. For
8 example, adding customers and the related revenue growth can help “pay for”
9 increases in operating expenses, or declines in usage per customer. The decoupling
10 proposals of Staff, NWEC and PSE do nothing to recognize that new gas sales and
11 margins produced by connecting new customers are available to help offset
12 declining usage trends associated with existing customers.

13 **Q. Does Staff witness Ms. Steward acknowledge the importance of matching all**
14 **elements of the revenue requirement calculation as well as the inconsistency of**
15 **piecemeal accounting for usage per customer declines between test years in her**
16 **testimony?**

17 A. Yes. At page 17, she states that decoupling should be allowed only as a pilot
18 limited to three years and explains that, “...decoupling addresses the level of
19 revenue the Company is recovering each year, based on what was authorized in a
20 rate case. Decoupling does not address the costs the Company is incurring each

⁷ NWEC witness Weiss (page 17) and Staff witness Steward (pages 15-16) recommend that new customer average usage levels be recalculated each year based upon actual data, rather than assuming that new customers’ average demand levels are the same as the average demand of all existing customers.

1 year. In a rate case, the Commission examines what costs are incurred to serve
2 customers, overall and at the customer class level. While decoupling provides the
3 utility with the variances between actual and authorized revenues, it does not
4 provide for any variances between actual and authorized costs.” This reference to
5 balanced review of overall costs and revenues that are examined in a rate case is
6 what I referred to in my Direct Testimony as the matching principle. In apparent
7 recognition that decoupling violates the matching principle, Ms. Steward then states,
8 “If a decoupling mechanism is allowed to go on too long without a rate case, we risk
9 violating the cost-based principle of regulation by creating a potential mismatch
10 between current costs and rates.”

11 In my opinion, Staff’s proposed decoupling based upon changes in usage
12 per customer will immediately and directly violate the matching principle. It is not
13 a question of “risk” of violating the matching principle or concern about “potential
14 mismatch” problems that should be tolerable for only a few years. Any decoupling
15 tariff that tracks changes in usage per customer in isolation is improper piecemeal
16 ratemaking that should be avoided.

17 **Q. Referring again to the testimony by Ms. Steward at page 17, what is your**
18 **understanding of her statement, “...decoupling addresses the level of revenue**
19 **the Company is recovering each year, based on what was authorized in a rate**
20 **case”?**

21 A. I understand that Staff’s recommended decoupling would ensure that future margin
22 revenues would be recoverable by PSE from existing customers on rate schedules

1 subject to decoupling, at the dollar levels authorized in the rate case, except for
2 variances caused by weather. The mechanics of the decoupling would “take into
3 account the new customers” that are added, using the approach described at pages
4 13-14 of Ms. Steward’s Direct Testimony, essentially allowing customer-driven
5 margin revenue growth to be retained for shareholders outside of the decoupling
6 tracker. Customer growth was not mentioned by Ms. Steward in her discussion of
7 changing costs and “authorized revenues”, but there is no denying that ongoing PSE
8 customer growth will add new margin revenues above “authorized revenues” that
9 should not be ignored in the design of a decoupling mechanism.

10 **Q. At page 21 of his testimony, Mr. Weiss concludes that, “The main goal of the**
11 **Coalition in this proceeding is to align the interests of consumers and**
12 **shareholders in order to encourage and empower consumers to participate in**
13 **both utility and non-utility measures that cost-effectively reduce gas usage.”**
14 **Similarly, at page 8, Ms. Steward states, “Further, I recommend that the**
15 **Commission adopt, as a pilot, a partial decoupling mechanism that will remove**
16 **PSE’s disincentive to promote energy conservation by restoring lost margin**
17 **due to customers’ non-weather related changes in usage.” Is decoupling**
18 **necessary to “align interests” or to promote energy conservation?**

19 **A.** No. The decoupling proposals being advanced by PSE, Staff and NWECA are over-
20 reaching, unbalanced and unnecessary. These proposals would shift most or all of
21 the risks of declining usage per customer between rate cases from shareholders to
22 customers, whether such usage declines are caused indirectly through price

1 elasticity, ongoing appliance replacements and building upgrades, or are caused
2 more directly through explicit company-sponsored conservation efforts. There has
3 been no showing that customers are better off after absorbing the expected
4 decoupling rate increases from such shifts. On the other hand, every decoupling
5 proposal being advanced in this docket is fundamentally flawed in not properly
6 offsetting future declines in sales per customer with the expected increasing sales
7 volumes and margin revenues from serving new customers. Historically, overall
8 PSE gas sales volumes are not declining because new customer sales growth has
9 offset declining usage per customer.

10 With respect to the alleged need for decoupling, it should be noted that
11 PSE has not failed in its efforts to deliver energy efficiency programs historically, in
12 spite of the alleged disincentive under traditional regulation to do so. Ms. Steward
13 states at page 10, “PSE has set reasonably aggressive targets for energy efficiency
14 programs, which it has met or exceeded for the last several years.” This is not
15 surprising because PSE, like any gas LDC, will need to continue to promote the
16 efficient use of its service to retain existing customers, attract new customers and be
17 able to succeed financially in the future. To the extent it is established that there is a
18 need for additional incentives for energy efficiency, decoupling is not a desirable
19 mechanism for the reasons explained in this testimony.

20 It is my conclusion that traditional test year ratemaking, through which all
21 changes in revenues, investment, expenses and cost of capital are measured at a
22 consistent and “matched” point in time, has been effective in aligning and

1 reasonably balancing the interests of PSE gas customers and PSE shareholders.
2 Declining gas usage per customer has existed for many years for PSE and other
3 LDC's and has been adequately addressed through traditional ratemaking and
4 without decoupling. No changed circumstances exist today that are sufficient to
5 justify adoption of extraordinary and complex piecemeal tariff tracking of changes
6 in usage per customer for PSE's gas utility.

7 **Q. Does this conclude your Cross-answering testimony?**

8 A. Yes.

BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

**IN THE MATTER OF THE PETITION BY)
PUBLIC SERVICE COMPANY OF NEW)
MEXICO FOR A REVISION OF ITS RATES,)
RULES AND CHARGES PURSUANT TO)
ADVICE NOTICE NOS. 755 AND 756)**

Case No. 06-00210-UT

**PUBLIC SERVICE COMPANY OF NEW)
MEXICO,)**

Petitioner.)

FINAL ORDER PARTIALLY ADOPTING RECOMMENDED DECISION

THIS MATTER comes before the New Mexico Public Regulation Commission (“Commission”) upon the Recommended Decision of the Hearing Examiner (“RD”) issued May 23, 2007, by Lee W. Huffman. Having considered the RD (attached hereto as Exhibit 1 and incorporated herein by reference), the Exceptions and the Replies thereto by the parties in this case, the record in this case, and being fully informed in the premises,

THE COMMISSION FINDS AND CONCLUDES:

1. The Statement of the Case and Discussion and all findings and conclusions contained in the RD are hereby incorporated by reference as Findings and Conclusions of the Commission, except to the extent expressly modified or disapproved herein.

2. Although the RD contains a summary of the positions of the parties, for the convenience of the reader, the Commission will reiterate those positions here:

PARTY	INCR.	ROR	ROE
PNM	\$21,305,330	8.72%	11.00%
Staff	10,183,316	7.43	8.50
AG	1,665,534	7.43	8.50
NNSA	(10,802,422)	7.43	8.50
RD	11,484,151	7.9633	9.53

3. PNM, Staff, the AG, UNM, the United States Department of Energy and the United States National Nuclear Security Administration (collectively "NNSA"), NRDC/SWEEP and Community Action New Mexico filed Exceptions to the RD. PNM, Staff, the AG, UNM, and NNSA filed Responses or Replies to Exceptions. The AG filed a Motion to File Response to Exceptions Out of Time.

I. COST-OF-SERVICE.

A. Return on Equity.

4. NNSA and Public Service Company of New Mexico ("PNM") were the only parties that filed Exceptions to the Hearing Examiner's recommended Return on Equity ("ROE") of 9.53%.

5. In its Exceptions, NNSA asserts that the RD does not explain why the 8.73% ROE that results from using the BR growth rate is too low, and why the floor is established at 9.315%. NNSA also contends that the general practice adopted by this Commission and other regulatory commissions is to set the ROE equal to the average of the highest and lowest computed values. But NNSA then asserts that the ROE in this case should be determined by using the average of the ROEs shown on pp. 53 and 54 of the RD, and not just the highest and lowest rates. According to NNSA, the resulting average ROE is 9.17%, and only that number should be approved as the ROE in this case.

6. PNM asserts that the RD ignores the undisputed fact that the average ROE authorized by state commissions for gas utilities in the United States in a total of 55 cases was 10.59% in 2004, 10.46% in 2005, and 10.49% in 2006. Such results, PNM argues, necessarily have a bearing on this case because other gas utilities are enterprises having corresponding risks to PNM, and an order authorizing a lower ROE for PNM could cause the financial community to have concerns relating to the enterprise's ability to maintain and attract capital. In support of its argument, PNM cites in a footnote to the decision of the Missouri Public Service Commission ("MPSC") in which the MPSC stated that "the national average [ROE] is an indicator of the capital market in which KCPL [the utility] will have to compete for necessary capital."¹ In a similar vein, PNM argues that although critical of Dr. Hadaway's use of a nominal GDP growth factor, some of the cases referenced in the RD resulted in authorized ROEs significantly above that proposed by the RD. The ROEs approved in those cases were, according to PNM, 10.045% and 10.2%. PNM goes on to cite a number of other cases in which an ROE higher than the 9.53% ROE recommended by the Hearing Examiner was approved.

7. Turning to the RD's methodology for determining the ROE in this case, PNM contends that the Hearing Examiner's methodology was never presented at the hearing, was never subject to cross-examination and that the methodology results in an ROE that is inconsistent with other well-reasoned decisions, as well as analysts' growth factors and sustainable growth estimates. According to PNM, the RD cites no authority for the methodology used except that the "Commission in a number of cases has relied on

¹ PNM's Exceptions, at 7, n.2, citing, *In the Matter of the Application of Kansas City Power & Light*, Case No. ER-2006-0314, Report and Order issued December 21, 2006, pp. 20-21, hereinafter cited as "KCPL".

Value Line predictions in determining a return on equity."² But, PNM observes, the RD goes on to reject the 9.9% ROE based upon the Value Line growth estimate because it is above Dr. Hadaway's 9.7% ROE Traditional Constant Growth DCF Model, which included as one fourth of its input the GDP figure of 6.6%. In so deciding, PNM contends, the RD erred because the Hearing Examiner had already removed the 6.6% GDP figure from Dr. Hadaway's Traditional Constant Growth DCF calculation.

8. PNM asserts that the RD's use of growth rates resulting from the various averages described in the RD was unaccompanied by an explanation of why the calculation and use of those average growth rates to determine the ROE in this case was useful or of its underlying economic purpose. PNM complains that the result obviously is to lower the results of the model. PNM concludes by asserting that while the Commission must exercise judgment in determining a proper ROE, it should consider all of the evidence presented, including results reached in other gas utility rate proceedings across the country, weigh the credibility of the witnesses, and, if it uses a model, make sure that it is theoretically sound and free of mistakes. Such judgment, PNM argues, should lead to a plausible and sensible result that is not biased in favor of any desired result.

9. On June 11, 2007, Staff and NNSA filed their Responses to Exceptions. The AG filed its Responses to Exceptions on June 12, 2007. These three parties were the only parties that responded to PNM's Exceptions to the Hearing Examiner's recommended determinations on PNM's ROE.

² *Citing Recommended Decision*, at p. 52.

10. In its Response, Staff responds to PNM's assertion that the MPSC, in *KCPL*, used the nominal GDP growth rate recommended by Dr. Hadaway by citing to a portion of the *KCPL* decision in which the MPSC explained that it had authorized the higher ROE proposed by Dr. Hadaway based partly on the MPSC's finding that Dr. Hadaway's credentials are superior to those of other ROE expert witnesses.³ Staff contends that while credentials may serve to indicate a witness's experience and expertise, it does not address the question of whether the actual testimony is correct or even reasonable. Other than the *KCPL* decision, which Staff considers to be flawed, Staff observes that PNM cites to no other authority in support of Dr. Hadaway's methodology. Asserting that determining an appropriate ROE is difficult and that one "correct" rate does not exist, Staff concludes by supporting the RD's recommended ROE of 9.53% as within the range supported by the testimony in this case.

11. NNSA argues in its Response that the ROEs allowed in other jurisdictions are not relevant to the ROE to be allowed to PNM in this case because each utility is different. Without the record from each of these cases, NNSA asserts, the Commission cannot determine how the jurisdictions derived specific ROEs or that PNM's financial characteristics are so similar that PNM's ROE should be based on ROEs from other jurisdictions. NNSA also rejects PNM's criticism of the RD's methodology of determining the recommended 9.53% ROE, arguing that PNM has not provided any reasonable calculation of why the RD's calculations are wrong. Like the RD, NNSA contends, PNM fails to support the use of the high end of the range of ROEs. NNSA also responds to PNM's arguments by citing to a number of decisions in which the New

³ Citing, *KCPL*, *supra*, at 29.

Mexico Supreme Court has recognized, among other matters: "There is a zone of reasonableness within which the Commission is free to set a fair rate of return."⁴

12. The AG, in its Response, counters PNM's assertions by arguing that the RD did in fact carefully consider the decisions of other state commissions when it correctly noted that the majority of states place primary reliance on the DCF model, and that no state utility commission had ever accepted Dr. Hadaway's proposed use of nominal GDP as the growth rate in the DCF model. Like NNSA, the AG asserts that the Commission must examine each on its own merits. For example, the AG notes that in *KCPL*, the utility in that case had requested pre-approval of long-term rate plans in order to facilitate construction of a new coal-fired generating unit and other capital projects that were expected to cost the utility over \$1.3 billion over the next five years. Given those capital requirements and the long-term rate plans approved by both the MPSC and the Kansas utility commission, the framework used to establish the utility's ROE, the AG asserts, is likely to be very different from the framework that is appropriate for PNM's gas operations in New Mexico. The AG concludes by asserting that the Hearing Examiner's recommended ROE is deliberative and thoughtful, and recommends that it be adopted by the Commission.

13. NNSA's contention that the Commission should determine the ROE in this case simply by using the average of the ROEs shown on pp. 53 and 54 of the RD should be rejected by the Commission. As stated in PNM's Exceptions, a renowned expert in the field of regulatory finance has aptly observed:

⁴ NNSA's Reply Exceptions, at 3, citing *State v. Mountain States Telephone & Telegraph Company*, 54 N.M. 315, 338, 224 P.2d 155 (1950).

The DCF method cannot be applied in a robotic, mechanistic manner. Mechanical approaches designed to simply insert numbers into an algebraic equation without regard to the reasonableness of those inputs in a regulatory setting must be avoided.⁵

14. This Commission will at times, such as in this case, take the averages of various growth estimates when, in the Commission's judgment, the use of such averages is appropriate to determine the ROE in a case. NNSA provides no explanation of why the averages of the various ROEs shown on pp. 53 and 54 of the RD are reasonable or appropriate in this case.

15. PNM's assertion that the Hearing Examiner ignored the ROEs granted by other state commissions in recent years should also be rejected. The RD cites to a number of decisions by other state commissions that directly support the proposition that this Commission is not bound by the allowed returns approved by other state commissions, and will not be repeated here. The Commission would note, however, that in *KCPL*, the decision that PNM heavily relies upon and attaches to its Exceptions, the MPSC expressly echoes the view that a utility commission's return on equity finding should not "unthinkingly mirror the national average."⁶ As illustrated by the AG's description of the factual backdrop to the MPSC's *KCPL* decision, each case must be determined on its unique facts and circumstances. Thus, while not ignoring the ROEs granted by the other states, the Commission's decision should not be determined by the returns granted elsewhere, but must be determined relying on the Commission's expert judgment and guided by the record evidence in this case.

⁵ PNM's Exceptions, at p. 10, citing *Regulatory Finance*, Roger Morin, Public Utility Reports, Inc. (1994).

⁶ *KCPL*, *supra*, at 20-21.

16. PNM's argument that the Hearing Examiner's proposed methodology is flawed because it was never presented at the hearing or subject to cross-examination is also without merit. As stated in *Re Public Service Company of New Mexico*, the "Commission can mix and match testimony and calculations and set a reasonable return that is not a figure that any single witness recommends."⁷ In other words, the test is not whether the Commission's determinations in a case were previously presented in a hearing and subject to cross-examination, but whether the facts relied upon to make that determination were presented in the hearing and subject to cross-examination. All of the ROEs shown in pp. 53 and 54 of the RD are based on dividend yields and growth estimates that were submitted by PNM's own witness, Dr. Hadaway and subject to cross-examination in the hearing this case.

17. PNM also errs when it asserts that the Hearing Examiner rejected the 9.9% ROE resulting from the use of the Value Line growth rate based on Dr. Hadaway's Traditional Constant Growth DCF Model, but after eliminating Dr. Hadaway's proposed 6.6% GDP implicit growth factor. Contrary to PNM's assertion, the 9.7% ROE determined by the Traditional Constant Growth DCF model did not reflect the elimination of Dr. Hadaway's 6.6% GDP figure. Rather, the 9.7% ROE is taken directly from PNM Exh. SCH-3 Rebuttal, which clearly reflects the inclusion of the 6.6% GDP figure.

18. Turning to the Hearing Examiner's method of determining the recommended 9.53% ROE, although the Commission does not necessarily agree with or

⁷ 73 P.U.R. 4th, 617, 631 (N.M.P.S.C 1985).

endorse the RD's methodology, the Commission nonetheless substantially agrees with the Hearing Examiner's recommended 9.53% ROE.

19. As a threshold matter, and although not challenged by PNM, the Commission agrees with the Hearing Examiner's recommendation that PNM's Traditional Constant Growth DCF model, after eliminating Dr. Hadaway's proposed nominal GDP growth factor, should provide the basis for determining the ROE in this case. As recognized by the Hearing Examiner, the Commission is part of the majority of states that place primary reliance on the DCF model, and no party, including PNM, has presented any credible alternative methodology as a basis for determining PNM's ROE.

20. The Commission also agrees with the Hearing Examiner's recommendation that Dr. Hadaway's nominal GDP growth factor should be rejected for the reasons stated in the RD and in the decisions of a number of other state commissions that are cited in the RD. Although the Commission agrees with the RD's other findings and citation to the decisions of other state commissions with respect to this issue, the Commission finds particularly compelling the Hearing Examiner's finding that PNM has failed to show that investors expect the growth of Dr. Hadaway's comparable group of natural gas utilities to be the same as the overall economy, especially where that overall economic growth is based on Dr. Hadaway's 1947 -2004 nominal GDP average growth.

21. Although the Commission agrees with the Hearing Examiner's rejection of Dr. Hadaway's GDP growth factor, the Commission disagrees with the Hearing Examiner's determination that the reasonable range of ROEs in this case is between 9.315% and 9.535%. The Commission finds that although the record in this case supports the RD's determination that the 8.88% and 8.73% ROEs resulting from the use

of the Zacks and BR growth rates are too low, the RD offers no explanation for not including in his range of reasonable ROEs the 9.17% ROE that results from using the average of the Value Line, Zacks and BR growth rates. As recognized by the RD, the Commission has often relied upon the Value Line and BR growth factors to determine the appropriate ROE in previous cases. The fact that the Zacks growth factor (4.65%) is between the BR (4.50%) and Value Line (5.67%) growth factors is a good indication that the Zacks growth factor also provides a valid measure of growth. Although the ROEs resulting from the use of the Zacks and BR growth rates alone are too low, the averaging of those rates with the much higher Value Line growth rate results in a growth that, at the very least, is at the lower end of the range of reasonableness. Given these considerations, the Commission finds that using the average of these three credible measures of growth is reasonable, and that the 9.17% ROE resulting from that average should be the floor of the range of reasonable ROEs in this case.

22. As for the top end of the range, the Commission agrees with PNM's assertion that the RD erred when it rejected the 9.9% ROE as too high. The RD rejected the 9.9% ROE, in part, because it exceeded the 9.70% result in Dr. Hadaway's Traditional Constant Growth DCF model. As discussed, *infra*, that model included as one-fourth of its input Dr. Hadaway's 6.6% GDP growth factor. The mere fact that the 6.6% growth factor was used as one of four growth factors does not, however, provide a valid basis to conclude that anything that exceeded the 9.7% ROE was outside the zone of reasonable ROEs. As illustrated by the averaging of the BR, Zacks and Value Line growth factors, the averaging of the 6.6% GPD growth factor with those three other growth factors could result in a growth factor and ROE that is within the range of reasonableness. Having

determined that the 9.7% ROE does not provide a valid basis for rejecting the 9.9% ROE, the Commission agrees with PNM that, in light of the Commission's long-standing reliance upon Value Line as an accepted measure of growth, the 9.9% ROE resulting from the use of the Value Line growth factor should be found to be within the range of reasonableness. Under the facts and circumstances of this case, the 9.9% ROE also appears to be at the top of the range of reasonable ROEs.

23. In light of the foregoing, the ROE that should be approved in this case falls somewhere between a floor of 9.17% and a ceiling of 9.9%. The Commission finds that the ROE in this case should be determined by taking an average of those two extremes, which is 9.535%. Although the Commission and the Hearing Examiner used different routes to arrive at substantially the same ROE, it is "the result reached, not the method employed, which is controlling." *Hobbs Gas Company v. New Mexico Public Service Commission*, 94 N.M. 731, 734, 616 P.2d 1116, 1119 (1980). We find that an ROE of 9.53% is within the zone of reasonableness, is consistent with the results of the DCF analyses, and should be approved in this case.

B. Cash Working Capital.

24. PNM proposes to include in rate base \$5,569,273 of Cash Working Capital ("CWC"), of which \$2,611,346 (NNSA Brief in Chief, Errata, Reconciliation Statement p. 1, l. 18) is attributable to the 2.7 days expense/revenue lag for its purchased gas supplies. The Hearing Examiner approved inclusion in rate base of the entire amount proposed by PNM. The AG and NNSA take exception to the RD in this respect.

25. The AG states that because PNM already earns a return on the over recovery of revenues reflected in the PGAC, earning a return on any lag in recovery of

revenues for gas sales would amount to double recovery. Therefore this amount should not be accorded rate base treatment according to the AG.

26. NNSA states that there is no reason to include CWC attributable to gas purchases in base rates to transportation customers, since transportation customers are not charged for gas purchases. NNSA further argues that if these costs are not excluded from transportation rates, the result is subsidization of sales customers by transportation customers, which thwarts competition.

27. PNM responds that the lag in collection of revenues is not already compensated by the return on the under-collected balance in the PGAC, because that balance relates to the recognition of revenue and the receivable resulting from billing activity, not to the exchange of cash. The lead/lag study to determine cash working capital needs relates to the exchange of cash. PNM further argues that part of the under-collected balance in the PGAC is the result of PNM eliminating the swings in gas prices to customers. PNM also states that NNSA's arguments are based on its objections to not having transportation rates further unbundled from sales rates. Finally, PNM's position is that transportation customers also benefit from services provided by purchasing functions, such as balancing, since they assure that the company's system will maintain pressure.

28. The Commission finds the arguments put forward by the AG to be persuasive with respect to the disallowance of rate base treatment of CWC related to gas purchases. Therefore, \$2,611,346 of the proposed CWC should be disallowed.

29. PNM proposes to eliminate the accumulated deferred income taxes ("ADIT") liability associated with the PGAC from the test period, on the rationale that

items related to the PGAC are not collected through the cost of service rates. Harland Direct at 9. The PGAC ADIT is a benefit the company derives from timing differences in the manner that gas purchase expenses and revenues are recognized for tax purposes. Tr. 12/13/06, at 219 – 221. According to PNM witness Harland, the tax treatment results in a \$9.8 million cash benefit to the company, as a result of its activities to purchase gas on behalf of its customers. Id. at 223. Presently, this benefit is not shared with customers through the PGAC. PNM Rule 25. The Commission finds that this benefit should be an offset to customer costs. While this item might be best included in the PGAC, tax items are not presently addressed in PGAC computations. The Commissioner therefore finds that the ADIT associated with the PGAC should be treated as a reduction to CWC for the cost of service.

30. In addition, the Commission finds that the inclusion of CWC, along with other items related to gas purchases, in PNM's PGAC should be investigated by the Commission in a separate proceeding, in order to achieve a better matching and recognition of all revenues and expenses attributable specifically to the cost of gas, as provided in NMSA 1978, § 62-8-7(E) and (F). The items to be investigated should include, without limitation, CWC; tax issues, consistent with this Order; the rate to be used for the applicable carrying charge on the over/under-recovered balance; and company-used and lost and unaccounted-for gas. Until a new determination is made as a result of this new proceeding, PNM should apply its pre-tax composite cost of capital as determined in this rate case to determine the applicable carrying charge on any under/over-recovered balance in the PGAC.

31. Except to the extent granted in this discussion, the AG's and NNSA's Exceptions with respect to CWC should be denied.

C. Construction Work In Progress

32. RD allowed \$17.3 million of Construction Work in Progress ("CWIP") in rate base. Following the recommendation of NNSA, the RD recommended the disallowance of \$6.6 million of CWIP for projects to be completed more than 150 days after the close of the base period.

33. PNM excepts to the exclusion of any amounts of CWIP that will be complete as of the date that rates go into effect. PNM states that all proposed CWIP was completed and in service by April 2007 and will be in use providing service to customers as of the date that rates go into effect.

34. Staff and NNSA responded to PNM's Exception. Staff states that Commission precedent allows CWIP for a year after the base period but not later, and to allow later CWIP impacts ratepayers negatively because it is not used and useful until implemented. Staff supports the RD.

35. NNSA states that PNM's proposal to include all CWIP does not meet both criteria of Case 1787, which is the applicable precedent, and which is cited by PNM. The additional CWIP that PNM proposes is not "short term" as required by Case 1787, because it was not complete as of 150 days after the close of the base year, even though it meets the criterion of being complete before rates go into effect.

36. The Commission finds that the recommendation of the RD is supported by the record and applicable precedent, and that PNM's Exception should be denied on this issue.

D. Recovery of Bad Debt.

37. The Attorney General asserts that PNM's determination of bad debts based on a combination of net write-offs and additions to bad debt reserves results in a double recovery of costs. The Hearing Examiner rejected those claims.

38. As AG witness Andrea Crane stated in her Direct Testimony at p. 40, PNM accounts for its write-offs on a cash basis by recognizing its actual base period write-offs, reduced by the amount of subsequent recovery of those write offs. Then, according to Crane, PNM also made an adjustment to increase net additions to the bad debt reserve during the base period, which is an accrual method. Then PNM allocated the results between gas and non-gas operations. Crane concludes that this hybrid of cash and accrual amounts to double counting of write-offs.

39. Although not raised in Exceptions, the Commission finds that the AG's argument has merit. Therefore, \$845,792 in uncollectible costs should be eliminated from PNM's bad debt reserve additions, leaving PNM's net write-offs as an appropriate measure of bad debt expense.

E. Results Based Pay.

40. PNM proposed to recover \$3,477,880 for its results based pay program. The AG and NNSA recommended that 50% of the costs be disallowed. Staff recommended disallowing 80% of those costs, or \$2,782,304. The RD adopted Staff's position.

41. PNM took exception to this result. PNM argued that although 80% of its results based pay is based on meeting earnings-per-share ("EPS") targets, if the total amount paid, together with other forms of compensation is reasonable and provides

benefits to ratepayers or is not contrary to ratepayers' interest, then it should be allowed. PNM cited to Washington and California regulatory decisions in support of its position. PNM also stated that no EPS award is given unless service improvement goals are met, which account for the other 20% of the award. PNM maintained that the achievement of EPs goals simultaneously benefits ratepayers and shareholders, because increased EPS generally is the result of better performance by the company. PNM stated that any conclusion to the contrary is without factual support in the record and is contrary to legal standards.

42. PNM pointed out that testimony in the record showed that results pay is a substitute for base pay and is only one element of compensation. According to the company, without results pay, PNM's total cash compensation would only amount to 85% of market medium, making it difficult to attract and retain quality employees. Thus, PNM would need to increase base salaries significantly, which would become fixed costs regardless of the performance of the company.

43. PNM noted that there was very little challenge to salary levels and no claim that they were unreasonable or above appropriate market levels. PNM claimed that this argument is supported by the fact that both the AG and NNSA proposed only a 50% disallowance.

44. Staff responded to PNM's Exception by supporting the RD. Staff expressed its position that the RD split of 20/80 appropriately aligns Results Based Pay objectives to the benefiting parties. Staff also stated that PNM has a fiduciary responsibility to conduct business to benefit ratepayers, with or without an incentive program. Staff opined that EPs targets are detrimental to ratepayer interests when

contributions for the program are incorporated into rates, payout is tied to EPS, and payout predictability is uncertain. The AG did not respond to this aspect of PNM's Exceptions.

45. The Commission is cognizant that attracting and retaining quality employees is an important goal for PNM. The Commission also recognizes that certain aspects of optimizing EPS may benefit ratepayers, as well as shareholders, such as cost control and other sound fiscal management, wise planning for growth and development and similar practices. However, the Commission perceives that by weighting the Results Based Pay goals so heavily toward EPS, there is a danger that EPS will be achieved at the expense of maintaining adequate quality of service. Moreover, the Commission has never before allowed Results Based Pay as an element of Cost of Service for ratemaking purposes. The Commission is persuaded by Staff's arguments, and, therefore, should adopt the recommendation of the RD. PNM's Exception on this issue should be denied.

F. Stock Options.

46. The RD recommends that the Commission permit PNM to recover \$815,159 to reflect what are characterized as additional benefit costs resulting from the adoption of FAS 123R. Although no party filed Exceptions to the Hearing Examiner's recommendation on this issue, the Commission, after reviewing the record on its own initiative, has determined that PNM's request to include the \$815,159 should be rejected on grounds that PNM has failed to meet its burden of proof that the requested amount is just and reasonable.

47. In the hearings in this case, the AG, through its witness, Andrea Crane, opposed the inclusion of the proposed \$815,159, asserting that FAS 123R is a reporting

requirement that has no impact on the actual cost of providing utility service, and that there is thus no reason to include those costs in PNM's revenue requirement determination. (Crane Direct, at p. 51.).

48. In response to Ms. Crane's assertions, PNM's witness, Thomas Sategna, asserted that stock options are a component of employees' total compensation and represents a cash expense for PNM. To explain how stock options represented a cash expense, Mr. Sategna explained that when an employee exercises a stock option, PNM gives its stock broker the money necessary to buy PNM's stock on the open market. (Sategna Rebuttal, at p. 31). PNM then sells the shares to the participant at the grant price. The broker, according to Mr. Sategna, then immediately sells the shares on behalf of the participant at the market price and returns the grant price times the number of shares to PNM. As a result of the foregoing transactions, PNM has a cash outlay equal to the difference between the option grant price and the market price at the time of execution. Sategna Rebuttal, at p. 33. Mr. Sategna also explains that prior to the adoption of FAS 123R, the costs of stock options were charged to Additional Paid in Capital, and reduced PNM's overall common-equity balance. Sategna Rebuttal, at p. 32. Finally, Mr. Sategna stated that, like other compensation plans, PNM records an expense in connection with PNM's stock compensation plan for base pay compensation and subsequently makes a cash outlay for that compensation to the employee. Sategna Rebuttal, at p. 33.

49. FAS 123R requires publicly-traded companies to recognize in their income statements the "fair value" of stock options and other compensation issued to employees as of the stock option's grant date, and to remeasure the fair value of that

award at each reporting date until the Option is exercised. In other words, and as acknowledged by Mr. Sategna, FAS 123R requires the recognition of compensation expense relating to the *granting* of stock options, and not to the *exercise* of the stock options by the employee. (Sategna Direct Testimony, at p. 32). The out-of-pocket expenses described by Mr. Sategna's testimony relate entirely to the costs incurred as the result of an employee's exercise of the stock option.

50. In light of the foregoing, the Commission agrees with the AG's initial contention that the \$815,159 requested by PNM is no more than an accounting entry reflecting the fair value of the stock options that were previously awarded by PNM. PNM has submitted no evidence showing whether and the extent to which its claimed \$815,159 amount reflects PNM's actual out-of-pocket expenses resulting from any employees exercising their options during the test period in this case. Additionally, although PNM's stock options have a ten-year term (Patterson Direct, at p. 9), PNM does not address the possibility that the costs for which it is seeking recovery today may not actually be paid by PNM for another ten years, and, if that occurs, why PNM should be permitted to retain the time value of those amounts. Indeed, Mr. Sategna appears to acknowledge this possibility when he stated that "PNM records a compensation expense for stock based compensation plans and makes a *subsequent* cash outlay to the employee for the stock compensation." Sategna Direct, at p. 33.

51. In summary, even if it is assumed that PNM should be permitted to recover its costs of stock options in light of FAS 123R, PNM has failed to meet its burden of proof to show that the \$815,135 reflects PNM's actual cost of those options. Accordingly, PNM's proposed \$815,135 increase in expenses should be disallowed.

G. Income Taxes.

52. PNM proposes to calculate its income tax expense on a stand alone basis. The AG and NNSA assert that PNM's income taxes should be calculated on a consolidated basis. The AG asserts that this methodology would result in reducing PNM's income taxes by \$86,752. (Crane Direct Testimony, at p. 71.) NNSA asserts that under its approach, PNM's income taxes should be reduced by \$5,593,568. (Kumar Direct Testimony, at p. 72).

53. The RD adopted PNM's proposal to calculate its income tax expense on a stand alone basis. This results in a total federal and state income tax expense of \$12,941,475. (RD, Exh. A, p. 7 of 8)

54. NNSA takes exception to this aspect of the RD. NNSA characterizes this as the allowance of "fictitious amounts of current income taxes" in the amount of \$10.4 million. (NNSA Exceptions at p. 18) NNSA argues that since the parent of PNM, PNM Resources ("PNMR") files on a consolidated basis, the subsidiaries should also calculate taxes on a consolidated basis, which would result in only \$1.6 million in tax expense for the test period. NNSA is of the opinion that Case 3137, which approved the formation of PNMR, required that PNM's payment to PNMR for income taxes must be limited to PNM's share of the current income tax.

55. PNM responds that the stand-alone methodology for income tax calculation for ratemaking purposes has been used for many years by this Commission and its predecessors. It is consistent with the stand-alone method for determining income and expense generated by the gas utility operations. Furthermore, according to PNM, if

the Commission is going to change its procedure for calculating taxes for ratemaking purposes, then it must have good reasons for doing so, citing *Hobbs Gas, supra*.

56. The Commission notes that PNM witness Matthew Harland testified about the deficiencies in both the AG's and NNSA's arguments for consolidated tax reporting. (Harland Rebuttal, pp. 24-27) It appears from the record in this case that the consolidated method of calculating income taxes may produce a different result. However, Harland's testimony does not contain sufficient detail, and other parties did not weigh in at a sufficient level of detail, for the Commission to determine whether the public interest would be served by changing Commission procedure for calculating income taxes for ratemaking purposes. Therefore, additional inquiry is justified into this subject. PNM and other interested parties are hereby put on notice that the Commission expects this issue to be addressed fully in PNM's pending electric general rate case, Case No. 07-00077-UT.

57. NNSA's Exceptions are without merit and should be denied.

H. Prepaid Pension Asset

58. The RD disallows rate base treatment for approximately \$17.6 million in funds in PNM's traditional defined benefit pension plan, estimated by PNM to be the difference between the amounts required by ERISA and the total funds contributed by PNM to the fund since 1987. The RD states that the amount claimed (1) is not required by ERISA to be paid into fund; (2) cannot be determined exactly, but is only an estimate; (3) would result in retroactive ratemaking; and (4) PNM did not demonstrate the source of funds used to pay into the pension fund.

59. PNM takes exception to the RD's recommendation. PNM maintains that its voluntary contributions in excess of ERISA requirements result in savings to ratepayers over time, which PNM estimates to be approximately \$1.1 million per year. Earlier voluntary contributions have meant lower required contributions now; without them, present required contributions would likely have been higher, according to PNM.

60. PNM also states that it is required to fund the plan pursuant to ERISA and the Internal Revenue Code ("IRC"). PNM must provide benefits earned by employees under the plan. SFAS 87 provides accounting rules for the cost of plan, but does not direct PNM in how to fund the plan.

61. PNM explains that funding of plan is governed by ERISA (minimum annual funding) IRC (maximum annual tax deduction). The actual expense incurred as required by ERISA is already being allowed as an operating expense; this claim deals with voluntary additional contributions being added to rate base and therefore earning a return at the authorized ROE. PNM argues that the RD demonstrates a misconception of PNM's claim when rejecting it as an expense that is not required.

62. PNM draws an analogy between its PPA claim and the ratemaking treatment accorded loss on reacquired debt that was approved by the New Mexico Supreme Court. *Re Petition of PNM Gas Services*, 129 N.M. 1, 10 (2000). There the court held that PNM's loss on reacquired debt should be passed on to ratepayers for ratemaking purposes, as long as there is a net benefit to customers. PNM argues that it has demonstrated that there is a net benefit to customers through its excess contributions to the plan, so that the reasoning of the *PNM Gas Services* case should apply.

63. PNM answers the RD's contentions as to the estimated nature of the amount of its claim by asserting that the court held in *PNM Gas Services* that an estimated benefit to ratepayers was sufficient. PNM goes on to state that UNM Exh. 3 is an excerpt from PNM's Form 10K that shows the actual difference between the amount funded and the amount expensed as per the books and records of the company at \$91 million, or approximately \$35 million more than the estimated amount used by PNM for its total prepaid pension amount. The Commission takes administrative notice of PNM's 10K for the year 2005 and makes it part of the record for this proceeding.

64. PNM counters the RD's recommendation on retroactive ratemaking by stating that this holding is contrary to *PNM Gas Services* – that case also was the result of contributions made several years prior which resulted in an asset (contributions were made in 1986 and 1994; rate base treatment was sought as of the end of test year 1995). PNM maintains correctly that the prohibition against retroactive ratemaking holds that past deficiencies may not be made up by excessive charges in the future. Here, PNM claims that past deficiencies are not being sought; recovery is being sought only on a current balance into the future, which is prospective.

65. PNM claims that the source of funding for the pension asset is not relevant, since the gas utility division has virtually one source of revenue – ratepayer bills for utility service.

66. Finally, PNM makes a new request to reverse the removal of AMPP from rate base if the PPA is not approved for rate base treatment (\$3.4 million).

67. Staff, UNM and NNSA responded to PNM's Exception. All three support the RD's recommendation to exclude the PPA from rate base treatment.

68. While Staff agrees with PNM that ERISA did not require excess contributions and that they were discretionary, Staff states that they were made for tax and financial benefits, not for the benefit of ratepayers. Moreover, while it is probable that without the additional contributions, PNM's annual pension expense required by ERISA would be higher, PNM's analysis of the benefit of the additional contributions is impermissibly based on estimates that do not correlate to the actuarial calculation of PNM's accrued pension costs.

69. According to Staff, the ERISA funding mechanism has an inherent true-up that provides the proper match of pension expenses in current rates to the pension liability over the remaining life of the program, and PNM's proposal is a hybrid between the accrued pension accounting of SFAS 87 and cash contribution that ignores the smoothing, true-up mechanism of SFAS 87. Staff argues that the proposal needlessly burdens ratepayers with inconsistent regulatory treatment and potentially duplicative recovery of pension costs over the life of the pension plan.

70. Further, Staff points out that the calculations between this case and PNM's electric general rate case are apparently not consistent, which causes concern. Finally, Staff states that there is no Commission precedent for the proposed treatment of the PPA.

71. UNM contends that the treatment of loss on reacquired debt is not applicable as precedent to determine proper ratemaking treatment of the PPA. Pension expense calculated pursuant to FAS 87 is included as a recoverable expense in O&M, so PNM is recovering its pension expense on a going forward basis. Required pension fund payments have been consistently approved by regulatory commissions as operating

expenses, but discretionary payments have not been consistently included in rate base. PNM's proposal seeks to change past Commission practice.

72. UNM also states that PNM's proposed PPA amount is based on purely hypothetical and unverifiable estimates of amounts of pension expense included in PNM's past and current gas service rates, which were prescribed from settlements where no specific pension expense amounts were approved by the Commission. Contrary to PNM's argument, according to UNM, the Commission should not rely on PNM's estimate of the PPA since it is \$35 million less than the \$91 million shown as accrued prepaid pension cost for 2005 shown on its 10K. PNM's claims that it followed a previous adverse witness's recommendation for its method of calculation to calculate benefit to ratepayers should be rejected because the use of this cost/benefit calculation is not applicable to this item. The referenced method was used in reference to loss on reacquired debt, and that precedent is not relevant, according to UNM. SFAS 87 is not applicable to loss on reacquired debt, but is applicable to funding pension fund. UNM argues that because the amount of the claim is based on estimates, the supposed "benefit" is entirely speculative.

73. UNM agrees with the RD that PNM's PPA claim violates the prohibition against retroactive ratemaking.

74. UNM notes that PNM itself raised the "source of funding" argument in the case. Therefore, the RD rightfully addressed issue. UNM maintains that ratepayers cannot be asked to pay a return on "ratepayer contributed capital," citing to FERC authority from its Response Brief at 11. Because PNM could not show that shareholders

were the exclusive source of capital to fund pension plan, UNM maintains that the Hearing Examiner properly found that PNM had not met its burden of proof.

75. NNSA's arguments are similar to UNM's. NNSA also argues that PNM has not met the criteria of *PNM Gas Services* with respect to the PPA.

76. The Commission finds that PNM has not met its burden of proof with respect to the inclusion of the PPA in rate base. Because the claim is based only on estimates, not on verifiable amounts, the Commission is not in a position to allow rate base treatment. In addition, PNM has not established that ratepayers benefit from any additional contributions. These reasons alone are sufficient to reject PNM's claim.

77. As to the arguments concerning retroactive ratemaking, that determination is not necessary to the decision in this matter. Therefore, the Commission declines to make any finding in that regard, and does not adopt the finding in the RD on that issue. Similarly, the Commission does not reach the issue of whether the source of funds used to pay excess contributions into the pension fund is determinative of, or even relevant to, the rate base treatment of those excess contributions.

78. PNM's Exception should be denied on the issue of exclusion of the PPA claim from rate base.

79. Finally, PNM's new request to reverse removal of AMPP from rate base if the PPA is not approved for rate base treatment should be denied. There is no support in the record for this request.

I. **Accumulated Depreciation.**

80. In its Exceptions, NNSA repeats its objection raised in the hearing in this case to the fact that PNM increased its depreciation expenses by \$1,684,376, but without

making any similar adjustment to the test period depreciation reserve. NNSA asserts that the RD should either exclude both the increased depreciation expense and accumulated depreciation, or include both. NNSA Exceptions, at p. 13. According to NNSA, it is inconsistent to use the year end plant-in-service and depreciation expenses and not to use the year end accumulated depreciation. NNSA requests the Commission to exclude the depreciation expense related to the new plant in service if the associated accumulated depreciation is to be excluded.

81. In its Response, PNM's states that, although it had increased its depreciation expense, it did not make a similar adjustment to its depreciation reserve for that amount because no portion of the cost of the new plant had been amortized through prior rates. In support of its position, PNM cites to an example presented by PNM's witness which demonstrated how NNSA's proposed adjustment would preclude PNM from ever earning a return of its total invested capital.

82. The Commission agrees with PNM's position and the RD's reasoning that if accumulated depreciation is booked during the test year before any depreciation takes place, PMM will never be able to recover the full amount of its investment. RD at p. 74. Accordingly, the Commission denies NNSA's Exception on this issue.

J. Advertising Expenses.

83. NNSA is the only party that filed Exceptions to the RD on this issue, and argues that the Commission should disallow \$1 million of the advertising costs recommended for approval by the RD, which includes \$485,000 related to the production and mailing of the weatherization program kits and \$385,000 in increased media advertising. Although the cost of the weatherization kit and increased media advertising

total only \$870,000, NNSA offers no justification for its position that the remaining \$130,000 of its proposed \$1 million reduction should also be rejected by the Commission.

84. With regard to the weatherization kit, NNSA cites to the testimony of Staff's witness that weatherization kits "are not a true informational and educational instrument," and that PNM excluded the weatherization kits in its recent Energy Efficiency Program Portfolio in Case No. 05-00261-UT because the results of this program is not measurable and verifiable. NNSA Exceptions, at p. 20. NNSA goes on to argue that PNM's customers did not need to be advised of high gas costs as they know it when they receive their bills. Instead of giving relief to high gas costs, NNSA contends, the RD allows PNM to increase their costs by another \$1 million on public relations and goodwill advertisement.

85. PNM responds to NNSA's arguments that the \$485,000 cost of the weatherization kits should be disallowed by citing to the testimony of PNM's witness Larson, who stated:

The weatherization kits really serve two purposes. The first was to actually and physically reduce the customer's energy use and, therefore, their bills during the high heating season, but secondly, the weatherization kit sends a strong signal to the marketplace and the customers that the prices were high. So by PNM doing something like distributing the weatherization kits, we were telling customers that something is different and pay attention to it by virtue of the fact that customers claimed so quickly, so they were communication tools from the standpoint of informing customers that something was different.

PNM Response, at p. 21.

86. With regard to NNSA's objections to the \$385,000 in additional advertising expenses, it appears that PNM assumes that NNSA intended to object to the \$335,000 in additional advertising expenses that NNSA challenged in the proceedings

below, and that NNSA's reference to the \$385,000 amount referred to in NNSA's Exceptions is a typographical error. In any event, PNM asserts that its witness, Mr. Larsson, explained in testimony in detail the \$335,000 by referring to the chart contained in his Rebuttal Testimony, to the expenses contained therein and sets forth the basis for the claimed \$335,000 increase in advertising expenses. PNM Response, at p. 22, *citing* Larson Cross, Tr. 12/14/06, pp. 30-32, PNM Ex. 10, Larson Rebuttal, at pp. 4-7. PNM asserts that NNSA's Exceptions raise no new arguments on this issued and should be rejected.

87. Turning to NNSA's position that a total of \$1 million should excluded, PNM argues that no explanation is given as to where this figure comes from or why it differs from the \$820,000 figure argued by NNSA before the RD was issued.

88. Before addressing the merits of NNSA's arguments, there appear to be some misunderstanding of the RD's recommended determinations on PNM's advertising costs that should first be corrected. PNM's assertion that the RD recommended approval of \$1,306,010 is in error. As discussed in the RD, PNM had requested to recover \$1,329,825 in informational advertising costs. However, of that amount, the RD recommended disallowance of \$238,481 for the weatherization kit expense (RD, at 96), and an additional disallowance of \$23,815 in expenditures for certain PNM publications. RD at pp. 96-97. As a result, the RD recommended that PNM be permitted to recover a total of \$1,067,529 in advertising costs, not the \$1,306,010 amount reflected in PNM's Exceptions.

89. Additionally, both NNSA's Exceptions and PNM's Response appear to assume that the RD approved the recovery of the costs associated with the weatherization

kit. In fact, the \$1,306,010 that PNM incorrectly asserts was the amount that the RD recommended for approval appears to include the cost of the weatherization kit that the RD recommended be disallowed. PNM did not file any Exceptions to the RD's recommended disallowance of the \$238,481, and thus PNM has presented no reason for the Commission to review the RD's recommended determination of that issue.

90. Turning to NNSA's arguments, NNSA provides no explanation for the amounts that are included in the \$485,000 amount that it asserts were the costs associated with the weatherization kit, or why that amount differs from the \$238,481 amount recommended for disallowance by the RD. From a review of the record, it appears that the source of NNSA's contention that PNM expended \$485,000 on the weatherization kit is PNM's to NNSA's discovery request, a copy of which is included as NNSA Exhibit JK-1, Schedule 71 to the Kumar Direct Testimony. However, PNM's response was that it had expended \$485,000 for the production and mailing of the "weatherization *programs*". As made clear from the rest of PNM's response, PNM used the term "weatherization programs" to refer to not just the weatherization kits, but also to weatherization DVD and Ace Hardware coupon reimbursement. The RD has recommended that the Commission approve PNM's request to recover the \$94,491 expense associated with the DVD weatherization and, as discussed below, NNSA has presented no evidence or arguments to support disallowing that expense. Further, because the \$238,481 amount was recommended for disallowance by the RD, and no party has filed any exceptions to that recommended determination, NNSA's arguments, to the extent that they relate to the \$238,481 disallowed by the RD, is moot and not the appropriate subject of an Exception. With regard to the remaining approximately \$152,000 of NNSA's claim (the difference

between \$485,000 reduced by the \$238,481 weatherization kit expense and \$94,491 DVD expense), NNSA fails to explain what those costs represent, much less provide any reason for disallowing them. The Commission should therefore deny NNSA's arguments with respect to the entire \$485,000.

91. With regard to NNSA's arguments regarding the \$385,000 amount for additional advertising, it is again unclear from the record in this case, what costs are included in that amount. Even if it is assumed that the amount includes the \$335,000 that was objected to by NNSA before the issuance of the RD, NNSA offers no justification for in its Exceptions for disallowing any costs included within that amount, or in the \$385,000 amount. The same is true with respect to the \$1 million amount that NNSA asserts should be disallowed. NNSA's Exceptions cite to no evidence in the record to support its assertion that the \$1 million is an unjustified public relations and goodwill expense.

92. For the foregoing reasons, NNSA's Exceptions to the RD's recommended approval of \$1,067,529 is denied.

K. Load Growth.

93. NNSA is the only party that filed Exceptions on this issue. In its Exceptions, NNSA objected to the RD's recommended approval of PNM's methodology to determine customer growth on its system. As correctly described by NNSA, PNM used 50% of the total year load growth to reflect the average number of new customers over the course of the following year. Applying that approach, PNM calculated a load growth of 1.16% for residential customers, and 0.65% for commercial. RD at p. 127. NNSA also asserts that the RD's description of PNM's methodology inaccurately

described PNM's methodology as using the difference between the number of residential and commercial customers at the end of the 2004 and 2005 to project its customer growth.

94. Instead of using 50% of customer growth, NNSA asserts that load growth should be determined by using 100% of the year-end or average year growth rates. NNSA also objects to the fact that PNM failed to make load growth adjustments for classes other than Residential Rate 10 and Commercial Rate 54 customer classes. NNSA asserts that neither PNM nor the Hearing Examiner addressed this second adjustment, and recommends that the Commission adopt both NNSA's recommended load growth adjustments.

95. PNM responds to NNSA's Exceptions by asserting that all of NNSA's objections to its use of one-half of total year growth to reflect the average number of new customers over the course of year were previously made to the Hearing Examiner, and recommends that the Hearing Examiner's recommendation on this issue be adopted by the Commission.

96. The Commission agrees with the Hearing Examiner's recommendation that NNSA's objections to PNM's methodology for determining load growth over the course of a year should be rejected for the reasons stated in the RD. NNSA's assertion that the RD mischaracterizes PNM's methodology should also be rejected. As the RD correctly states, PNM *used* the difference between the number of residential and commercial customers at the end of 2004 and 2005 to project customer growth for 2006. As made clear by the RD, the Hearing Examiner clearly understood that although the year-end differences in customers served as the *basis* for determining load growth, the

Hearing Examiner also correctly observed that because customer growth takes place over the course of a year, "PNM used one-half of the total year growth rate to determine the average number of new customers over the course of the next year." RD at p. 128.

97. The Commission also rejects NNSA's objection to the fact that PNM did not make load growth adjustments for the customer classes other than its Residential and Commercial customers. As explained in the Rebuttal Testimony of PNM's witness, Mr. John M. Fernald:

The other classes are small enough that PNM was able to review each customer in the class to determine if there were new customers to be annualized. Customers that were annualized or who changed service are reflected in PNM's test period revenues, as shown in the section on Change in Service in PNM Exhibit JMF-9 and JMF-10. Mr. Kumar's growth adjustment for these other classes [is] unnecessary, redundant and overstates the growth in other classes. His recommendations should be denied.

Fernald Rebuttal, at p. 13.

98. For the foregoing reasons, all of NNSA's Exceptions on this issue are denied.

L. Treatment of Unamortized Litigation Expense.

99. NNSA objects to the Hearing Examiner allowing PNM to include its unamortized litigation expense in rate base, and thus allow PNM to earn a return on that amount. To support its position, NNSA cites to two authorities, one of which states that amounts that are allowed to be amortized for ratemaking purposes are "amortized as an expense for the appropriate number of years, but the amortization reserve is *generally* excluded from a utility's rate base." NNSA's Exceptions, at p. 32, *citing* Charles F. Phillips, Jr., *The Regulation of Public Utilities* (2nd Ed. 1988), p. 256. NNSA also cites to another authority which states that a court upheld a decision by the Rhode Island

commission to exclude the unamortized balance of rate case expenses from rate base on the ground that "the commission could properly require a sharing of these costs between ratepayers and the company's shareholders." NNSA's Exceptions, at p. 33, *citing* Leonard Saul Goodman, *The Process of Ratemaking*, Vol. II (1988), at p. 743.

100. PNM responds to NNSA's arguments first by asserting that the inclusion of rate case litigation expenses in rate base is consistent with Commission precedent allowing a utility to amortize an extraordinary expense and to carry the unamortized portion in rate base over the period of time in which the rates are to be in effect. PNM's Response, at p. 23, *citing* Case No. 2147. PNM also asserts that the New Mexico Supreme Court has rejected NNSA's implicit assertion that that shareholders benefit from the filing of a rate case, where the court held that rate proceedings are conducted for the benefit of both ratepayers and shareholders. PNM Exceptions, at p. 23, *citing*, *In re PNM Gas Servs.*, 129 N.M. at 24. However, PNM goes on to assert that the court's decision should not be a consideration in determining whether PNM should be allowed to earn a return on the unamortized balance. Rather, PNM contends, PNM has expended incremental dollars to establish appropriate rates for its customers, and that sound cost of service theory allows for a return on shareholder cash expended that has not been recovered from ratepayers as long as the expenditures are determined to be reasonable. Because rate case expenses are recovered over a period of years similar to PNM's utility investment in plant, PNM argues, PNM's rate case expenses should be treated in a similar manner as other unamortized amounts included in rate base.

101. The Commission has had a long-standing policy of permitting PNM to include unamortized rate case litigation expenses in rate base as long as they are

reasonable. NNSA presents no arguments or evidence that would support either a finding that the unamortized rate case expenses are unreasonable or that the Commission's policy should be changed to exclude such costs from rate base. NNSA's Exceptions on this issue are denied.

II. RATE DESIGN AND OTHER ISSUES.

A. Weather Normalization.

102. PNM proposes to use a ten-year weather normalization adjustment, rather than the traditional 30-year weather normalization. The AG and NNSA support a 30-year period. Staff supports PNM's ten-year weather normalization proposal. Using the fixed 30-year period of 1975-2004 instead of the most recent ten years would decrease PNM's revenue requirements by over \$6.7 million. NNSA Brief in Chief, p. 49. The Hearing Examiner recommends the use of the most recent 15-year period.

103. The AG excepts to the RD. The AG argues that there is no evidence in the record to support the choice of fifteen-year weather normalization. AG witness Andrea Crane used 30-year decadal weather in calculating pro forma revenues using weather adjusted average through-put; the AG agreed to use the most recent 30 years rather than the most recent three decades. Also, weather normalization is an adjustment to actual test year revenues to reflect a pro forma level of utility income that would be realized assuming "normal" or "average" weather, and thus average through-put.

104. Crane also testified that the National Oceanic and Atmospheric Administration ("NOAA") defines "normal" degree-days and the average over specific 30-year decadal periods. According to Crane, 30-year data has been established by

international agreement as reflecting normal weather conditions, and NOAA “normal” is currently defined as the data for the period 1971 to 2000.

105. According to the AG, 30 years has been used in New Mexico rate setting for many years. PNM does not present any NMPUC precedent in favor of ten-year or other periods of time for weather normalizing revenues. Use of an accepted objective standard, such as the 30-year NOAA standard, ensures consistency from case to case. The Ag maintains that there is no other common standard. PNM admitted that 30 years has been the norm in the past.

106. As stated by the AG, although climate change and global warming may exist, there will still be variability in weather. Thirty-year normalization includes more data points, so each point has less impact and will be less likely to skew the calculation. The AG criticized PNM witness Gutzler’s conclusion that in the presence of a trend in climate there will be a limit to the usefulness of including additional data far removed in time from the present, and contends that Gutzler failed to compare the 30-year average from past periods with 10-year averages from past periods to show whether or not there is now a difference that did not exist in the past.

107. The AG looks to previous treatment of weather normalization in New Mexico. The NMPSC previously accepted a nine-year average for Southern Union Gas Company because there was insufficient data to do otherwise, but stated that a 30-year sample is desirable for doing a weather normalization adjustment. The NMPUC rejected ten-year weather normalization in Case 2662 over the recommendation of the Hearing Examiner; although case was overturned, the court upheld that aspect of case. The AG

argues that many commissions accept 30-year normalization (citing five cases from different jurisdictions).

108. Finally, the AG points out that the AG did not agree to the stipulation in PNM's last gas rate case, and thus did not agree to ten-year weather normalization being used in rate design.

109. NNSA makes much the same arguments as the AG. NNSA states that the Commission has consistently adopted a 30-year based average as normal weather, and that the 30-year average is internationally and nationally used standard practice. The RD does not demonstrate that Gutzler or the Hearing Examiner or any party is sure that the ten-year period is better. NNSA maintains that the Hearing Examiner ignored testimony that the purpose of weather normalization adjustment in ratemaking is not to forecast weather but to normalize sales for the Test Period, which is supported by the record. NNSA agrees with the AG that a longer period uses more data that results in a more stabilized basis for normalizing that will not change much from rate case to rate case.

110. NNSA states that deviation from the 30-year standard will cost ratepayers \$4.7 million per year. NNSA concludes that Gutzler's testimony is not sufficient to do more than give rise to a suspicion that there may be weather normalization period that may be better than ten-years.

111. PNM responded to the AG and NNSA by supporting the RD. PNM begins by contrasting the qualifications of the witnesses: Gutzler is a Ph.D. in field, whereas Crane and Kumar are not qualified in this technical area.

112. PNM cites Gutzler's calculation of the accuracy of the three decadal approach, a fixed one decade approach, and the most recent ten years approach in

predicting total heating degree days for the target period of 1996 to 2005, and his conclusion that the 30-year averaging period consistently and substantially overestimates average annual HDD totals during the past ten years at all six New Mexico sites studied to rebut the AG's argument that Gutzler failed to compare past 30-year and ten-year periods to show whether there is now a difference that previously did not exist.

113. PNM concludes that the AG and NNSA have presented no evidence to refute Gutzler's basic reason for departing from the use of the 30-year average – a general warming trend.

114. The Commission has examined the record and concludes that the AG's Exception should be granted to the limited extent that the RD's choice of a fifteen-year weather normalization period is not based on the evidence in the record and should be rejected. However, the Commission accepts the finding in the RD that PNM has met its burden of proof that the 30-year decadal weather normalization period should be rejected, based on the record before the Commission. The Commission also finds that PNM has met its burden of proof that the most recent ten-year period should be used for weather normalization, based on this record.

115. In addition, the Commission believes that the issue of determining the optimal period for weather normalization in light of a warming climate trend must be addressed more urgently than waiting for PNM's next gas general rate case. Therefore, the Commission should open a new rulemaking docket to address this issue, and to receive information concerning, at a minimum, five, ten, fifteen, 20, 25 and 30 year periods for use in the determination of average HDD in New Mexico for gas ratemaking purposes. This rulemaking docket should be opened without delay.

116. To the extent not otherwise granted, the Exceptions of the AG and NNSA should be denied.

B. PNM's Decoupling Proposal.

117. PNM proposes to decouple its sales volumes from the revenues it receives under a Consumption Normalization Adjustment ("CNA") under its proposed Rate Rider 16. The AG, UNM, NNSA and NMIEC opposed the CNA. Staff testified in favor of decoupling in general, and believed it possible that Staff and the other parties could fix flaws in Rate Rider 16 "if given adequate time and resources." RD at p. 119. The RD recommends finding that the shortcomings of Rate Rider 16 are not amenable to any fix, that decoupling is not in the public interest, and is inconsistent with the Public Utility Act. RD at pp. 122 and 125.

118. PNM and NRDC/SWEEP filed exceptions addressing the RD's treatment of this issue. PNM "seeks clarification" in its Exceptions that the RD should not be interpreted to mean that its proposal with regard to decoupling is not rejected by the Commission "with prejudice," *i.e.*, such that PNM may not bring the same proposal back to the Commission for consideration in a different proceeding. NRDC/SWEEP, on the other hand, takes issue with the substantive findings of the RD, as well as with the fact that the RD recommends rejection of the decoupling proposal with prejudice.

119. Addressing the issue of rejection with prejudice, the Commission finds that rejection with prejudice is appropriate in this case. The proposal put forth by PNM and supported by NRDC/SWEEP and Staff is overly broad and overreaching. If implemented, it would, in effect, make PNM whole for past conservation efforts of consumers that have absolutely nothing to do with the enactment of the Efficient Use of

Energy Act on which PNM relies for recovery for lost volumes. Moreover, PNM's proposal fails to take any account of customer growth that has occurred during the time that consumption per customer may have declined. Therefore, the Commission finds that the decoupling proposal advanced by PNM in this case is fatally flawed, and that the Commission will not consider it again in any case.

120. That is not to say, however, that the Commission will not consider a well-designed decoupling proposal that meets the criteria of the Efficient Use of Energy Act. The Commission welcomes appropriate measures to eliminate disincentives to investment by utilities in energy efficiency programs as contemplated by the Act. However, they must be narrowly focused to address those disincentives, and not be aimed at making the utility whole for all load losses.

121. NRDC/SWEEP's contentions in its Exceptions that the RD must address each item of evidence in the record separately are unfounded. The Public Utility Act simply requires that the Commission make ultimate findings, and that they be supported by evidence in the record. *See Attorney General v. NMPSC*, 101 N.M. 549 (1984). To the extent that a conclusion is contrary to a contention of a party, and to evidence in the record, there is an implicit finding that those arguments and evidence have been rejected. *See AG v. NMPUC*, 101 N.M. at 553-54 (1984).

122. To the extent not otherwise granted, the Exceptions of PNM and NRDC/SWEEP should be denied.

C. Minimum System Rate Design

123. The RD accepts PNM's rate design, as consistent with Staff's recommendation that includes a minimum 2" distribution system, based on past precedent.

124. The AG filed an Exception to this determination. The AG state that PNM allocated virtually all fixed costs in its allocated cost of service study using a peak and average methodology, except that it included a customer component of mains based on a hypothetical 2" minimum distribution system. The AG argues that this methodology improperly results in treating annual costs of a minimum size distribution system as customer costs.

125. PNM cites precedent for the use of the 2" minimum system.

126. UNM responded to the AG, and stated that the "zero-intercept" method advocated by the AG is "result oriented" and is not appropriate in a utility's cost of service study. UNM also criticized the zero-intercept method as resulting in even greater inter-class subsidies than the 2" minimum method.

127. The AG's arguments are not persuasive and the Exceptions should be denied.

D. Residential Access Charge

128. The RD adopts PNM's rate design, as supported by Staff, and adopts Staff's proposed residential access fee of \$10.26.

129. The AG and NNSA filed exceptions to this aspect of the RD. PNM supports the RD.

130. The Commission does not accept either the AG's proposal for a \$7.00 residential access fee, or NNSA's proposal for a single bill per customer, regardless of

the number of meters attributable to that customer. However, the Commission finds that an increase to \$10.26 shifts costs more than is desirable to the fixed portion of residential bills. Therefore, the class increase attributable to the residential class should be applied on a pro rata basis to all elements of the residential rate. This change will result in an access charge to residential customers that is less than \$10.00 per month.

131. To the extent not granted, the Exceptions should be denied.

E. Further Unbundling of Transportation of Gas from Purchase Gas Commodity.

132. In its Exceptions, NNSA asserted that the RD inappropriately rejected NNSA's proposals to further unbundle transportation rates. More specifically, citing to the principle that cost responsibility should match as closely as practicable the cost of providing service, NNSA asserts that the RD erred by allocating cash working capital ("CWC"), bad debt expenses and "Other Gas Supply" expenses related to PNM's purchase of natural gas to transportation customer rates. NNSA argues that these costs, which total approximately \$4.1 million, do not relate to providing transportation service, and that no party has disputed that assertion. NNSA Exceptions, at p. 7-8. According to NNSA, charging these unneeded costs to transportation service is not only contrary to the Legislature's and Commission policy of non-discrimination and competition, but also amounts to an illegal confiscation of transportation customers' funds. NNSA Exceptions, at 8.

133. NNSA also argues that the RD's reliance upon the Commission's decision in case No. 2147 to reject further unbundling is wrong because, according to NNSA, the issue in Case No. 2147 was not further unbundling, but whether the non-gas cost-of-service should be allocated separately to sales and transportation customers. *Id.* NNSA

goes on to argue that the Commission's decision in Case No. 2147 confirms that the transportation service cost-of-service and rates should be established in such a manner that the customers who decide to switch from sales to transportation or vice are not impacted. If, NNSA contends, PNM's gas supply service costs are charged to transportation customers, their decision will be impacted unreasonably and the legislative purpose will be frustrated. NNSA Exceptions, at p. 9.

134. In its Response, PNM argues that NNSA's position is disingenuous insofar as NNSA opposed PNM's request to that bad debts associated with gas costs be removed from the cost of service and added to the PGAC and took the position that such bad debt costs should instead be recovered through cost-of-service rates. PNM's Response, at p. 15. Now, PNM argues, NNSA is arguing that bad debts should be recovered through cost-of-service rates because, according to NNSA, those costs are gas costs and should not be recovered from transportation customers. PNM also asserts that NNSA, while proposing that there should be separate cost-of-service rates for sales and transportation customers, NNSA provides no cost-of-service study to support the level of rates that should be charged in those separate rates. PNM Response, at 16.

135. In response to NNSA's position on other gas costs, PNM states that the "other gas costs expenses" relate to PNM's gas supply and transportation department. Both sales and transportation customers, PNM argues, benefit from there being gas in the system because there must be adequate pressure in the system or no gas flows. According to PNM, transportation customers also benefit from hour-to-hour and daily balancing because PNM purchases a sufficient gas supply to maintain the pressure in the pipeline system. PNM also points out that employees in the gas supply and

transportation department provide exclusive service to transportation customers by providing services such as receiving nominations, contract administration and billing to transportation customers. Thus, PNM argues, NNSA would exclude all of the "other gas costs" without a study indicating what services benefit transportation customers. *Id.*

136. The Commission denies NNSA's exceptions with respect to all three types of gas supply related costs. In addition to the RD's reasons for rejecting NNSA's arguments, the Commission also agrees with PNM's argument that PNM's costs related to purchasing gas supplies for its system benefits both transportation and sales customers. As explained by PNM, transportation customers benefit from hour-to-hour and daily balancing because such balancing, and the gas supply costs associated with that balancing, helps to maintain adequate pressure in the pipeline system to ensure that sales and transportation customers receive the gas they expect. Based on the record of this case, the Commission finds that the gas supply related costs objected to by NNSA should be allocated to transportation customers.

III. MISCELLANEOUS ISSUES.

A. Elimination of Discounted Transportation Rate for Electric Generation.

137. Staff recommended that PNM be required to eliminate the discount for gas transportation to PNM's electric generating stations. Staff argued that it was inconsistent for PNM to be offering discounted transportation rates for its electric generation while at the same time implementing an energy conservation program. The Hearing Examiner recommends the rejection of Staff's position.

138. No exceptions were filed on this issue. However, because of the nature of these transactions, the Commission is of the opinion that additional inquiry is appropriate in the future to determine whether these discounts are justified and appropriate.

B. Late Charges.

139. Currently, PNM imposes a late payment charge of 1.5% a month, or 18% a year, on accounts over 30 days past due. CANM requests the Commission to eliminate the late payment charge entirely, or to limit its application so that it would apply only to accounts that are past due 60 days and have a balance of at least \$200, and to exempt low-income customers and those whose accounts are not subject to collection for regulatory reasons. PNM opposes CANM's proposal, asserting that without the late payment charge, PNM would have no incentive to pay their utility bills. The RD recommends that PNM's late charge be reduced to 13% per year, the same interest rate charged by credit card companies.

140. CANM's filed Exceptions, maintaining that the late charge should be eliminated entirely. Alternatively, even with a reduced charge, the late fee should be limited to accounts that are past due 60 days and have a balance of at least \$200, and exempt low-income customers and those customers whose accounts are not subject to collection for regulatory reasons. PNM did not respond to this aspect of CANM's Exceptions.

141. The Commission is sympathetic to both parties on this issue. On one hand, PNM may, in fact, incur costs because of additional late payments if the late fee is completely eliminated. On the other hand, the late fee should not be set so high that it

puts economically disadvantaged customers so much farther in debt for their utility bills that they can never recover.

142. Therefore, the Commission should modify the recommendation of the RD to set a late fee of 8% per year, or 0.667% per month. This rate is based on the composite cost of capital prescribed in this case of 7.96% and on the IRS interest rate of 8%. Customers whose accounts are not subject to collection or shutoff for regulatory reasons shall be exempt from the late fee. In addition, customers who meet the qualifications to receive assistance pursuant to the LIHEAP program from the administering authority shall also be exempt from the late fee.

C. Winter Moratorium.

143. CANM contends that PNM violated the winter shutoff moratorium statute, NMSA 1978, § 27-6-18. The alleged violations include the failure to provide pre-termination notices of winter shutoff moratorium protections, false and deceptive threats of disconnection and improper imposition of additional fees. The Hearing Examiner recommends that the Commission find that CANM's issues are outside the scope of this rate case, but make clear that its findings do not preclude CANM from pursuing these issues by filing a complaint with Commission, or by other legal process.

144. CANM has made serious allegations concerning PNM's conduct in this case. A general rate case involves the resolution of numerous complex issues relating to the minutiae of the company's cost of service and rate structure in a statutorily limited timeframe. That very complexity does not allow for the thorough exploration of these kinds of allegations that they deserve. Therefore, the Commission will open a new docket to investigate CANM's allegations.

145. To the extent not granted, CANM's Exceptions should be denied.

D. AG Motions.

146. In its Response to Exceptions, the AG requests the Commission to strike PNM's Exceptions to certain issues that were raised by PNM in its Brief-in-Chief and Reply Brief and incorporated by reference. As grounds for its request, the AG asserts that PNM's Exceptions did not comply with 17.1.2.39(C)(2) NMAC, which requires that "Exceptions . . . specify . . . the reasons for the exceptions. . ."

147. The AG also filed on June 11, 2007, a separate Motion to File Out of Time ("Motion"), which requested permission from the Commission to file its Response to Exceptions by June 12, 2007. In support of its Motion, the AG states that the Assistant AG responsible for this matter experienced a medical emergency that prevented him from completing his Response by the deadline.

148. The Commission finds that the AG's Motion for Leave to File Out of Time ("Motion") sets forth good cause for granting the Motion as required by 17.1.2.8(L) NMAC. Accordingly, the Commission should grant the Motion.

149. The Commission should deny the AG's motion to strike a portion of PNM's Exceptions. Given the significant economic, policy and other issues raised by this case, the Commission believes that the public interest would be served by affording the parties a reasonable opportunity to present to the Commission the issues that they believe should be examined by the Commission. Additionally, the AG has not alleged that PNM's raising a portion of its Exceptions by incorporation materially has prejudiced the AG or any other party.

150. The Commission has jurisdiction over the parties and the subject matter of this case.

151. Due and proper notice of this case has been provided.

IT IS THEREFORE ORDERED:

A. Except as expressly modified or disapproved herein, the Orders contained the RD as set forth in Exhibit 1 are incorporated by reference as if fully set forth herein and are ADOPTED, APPROVED and ACCEPTED as Orders of the Commission.

B. By no later than Tuesday, July 3, 2007, PNM shall file supporting analyses that contain the same types of information that is shown in Exhibits A through D of the Recommended Decision and verify that the revised rates that will be set forth in the new Advice Notices to be filed in accordance with this Final Order will generate the revenue requirements authorized by this Final Order. PNM shall also file by no later than 12:00 noon on Thursday, July 5, 2007, new advice notices and revised rates consistent with terms of this Final Order, and a statement by PNM that it has filed all documents by the deadlines specified in this Paragraph. By no later than Thursday, July 5, 2007, Staff shall review the advice notices, revised rates and supporting analysis filed by PNM. Unless otherwise notified by Staff, the revised rates shall go into effect for bills rendered on and after Friday, July 6, 2007.

C. Unless Staff notifies the Commission and PNM that any of the filings required by Paragraph B of this Final Order are not in accordance with the provisions of this Final Order, this docket shall be closed on Friday, July 6, 2007.

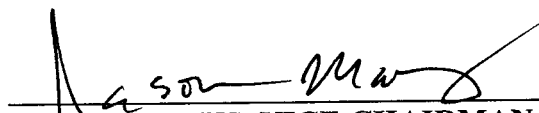
D. The AG's Motion is granted.

E. The AG's request in its Response to Exceptions to strike a portion of PNM's Exceptions is denied.

F. A copy of this Final Order shall be served on all parties on the attached Certificate of Service. A copy of the RD shall not be served with this Final Order due to the length of the RD, and because the parties already have a copy of the RD.

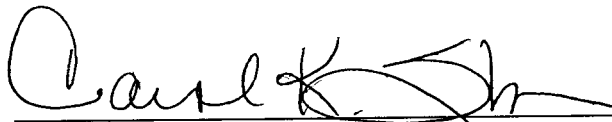
ISSUED under the seal of the Commission at Santa Fe, New Mexico, this 29th
day of June, 2007.

NEW MEXICO PUBLIC REGULATION COMMISSION


BEN R. LUJAN, CHAIRMAN
JASON MARKS, VICE CHAIRMAN

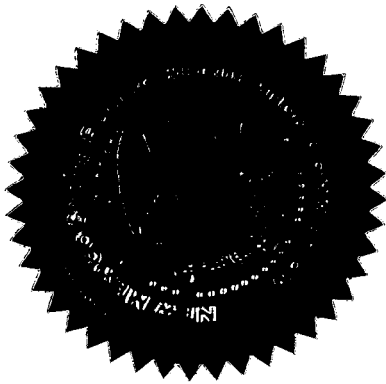
TELEPHONICALLY APPROVED

DAVID W. KING, COMMISSIONER


CAROL K. SLOAN, COMMISSIONER

TELEPHONICALLY APPROVED ,

SANDY JONES, COMMISSIONER



BEFORE THE NEW MEXICO PUBLIC REGULATION COMMISSION

IN THE MATTER OF THE APPLICATION
OF PUBLIC SERVICE COMPANY OF NEW
MEXICO FOR A REVISION TO ITS RATES,
RULES, AND CHARGES PURSUANT TO
ADVICE NOTICE NOS. 755 AND 756,

PUBLIC SERVICE COMPANY OF NEW MEXICO,

Petitioner.

Case No. 06-00210-UT

CERTIFICATE OF SERVICE

I HEREBY CERTIFY that a true and correct copy of **Final Order Partially Adopting Recommended Decision**, issued June 29, 2007, was mailed first-class, postage prepaid, to each of the following:

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and hand-delivered to:
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Staff Counsel – NMPRC
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Santa Fe, NM 87502-2013

and hand-delivered to:
Carol Smith Rising, General Counsel
NM Public Regulation Commission
1120 Paseo de Peralta
Santa Fe, NM 87504

and hand-delivered to:
Lee Huffman, Hearing Examiner
NM Public Regulation Commission
224 E. Palace Ave. – Marian Hall
Santa Fe, NM 87502

DATED this 2nd day of July, 2007.

NEW MEXICO PUBLIC REGULATION COMMISSION



Melissa Salas, Paralegal

**BEFORE THE TENNESSEE REGULATORY AUTHORITY
NASHVILLE, TENNESSEE**

IN RE:	)	
	)	
ALLEGED VIOLATIONS OF TENN. CODE ANN.	)	
§ 65-4-120 (2004) AND RULES OF THE	)	DOCKET NO. 05-00150
TENNESSEE REGULATORY AUTHORITY,	)	
CHAPTERS 1220-4-5-.08 AND 1220-4-5-.09 BY:	)	
	)	
ATMOS ENERGY CORPORATION	)	

SETTLEMENT AGREEMENT

This Settlement Agreement has been entered into between the Consumer Services Division ("CSD") of the Tennessee Regulatory Authority ("Authority" or "TRA") and Atmos Energy Corporation ("Atmos" or "the Company") and is subject to the approval of the Directors of the TRA.

I. FACTUAL BACKGROUND.

In May 2004, Atmos contracted with the Bush Meter Reading Company to assume regular meter reading duties for 21,000 of the Company's meters in the Murfreesboro area. The Bush Meter Reading Company assigned Atmos three of its meter-readers, and those individuals were trained by Atmos and began reading meters around June 2004.

In late November 2004, Atmos' internal system controls revealed problems with some of the meter readings from the Bush Meter Reading Company. Atmos' investigation revealed that two Bush Meter Reading Company employees had falsified readings by utilizing the previous month's information from the handheld meter reading device rather than actually reading the

customers' meters. A total of 14,055 customers may have received erroneous meter readings between August 2004 and December 2004. In addition, the falsified reads, based on the false information, failed to account for increased gas consumption as the weather turned colder into the fall of 2004. As a result, when those customers' accounts were tried-up, they received bills that were larger than usual in December, January, and February. Because Atmos' Purchased Gas Adjustment (PGA) remained unchanged from October 2004 through March 2005, all bills during the affected time period were at the same gas cost rate.

In December 2004, Bush Meter Reading Company terminated the employees responsible for the falsified meter readings. Atmos has terminated its contract with Bush Meter Reading Company and will resume reading all meters with Atmos employees.

Atmos notified the CSD of the customer billing problem on January 20, 2005. In response to the CSD's concern regarding the possibility that customers would incur late fees as a result of the larger than usual bills, Atmos removed all late fees from the account of all 14,055 customers who may have been affected.

Atmos also contacted the customers most significantly impacted, including setting up individual appointments with customers to discuss billing concerns. Through the media customers were notified to contact Atmos if they had questions about their bills and were advised that payment arrangements would be made available. On March 18, 2005, Atmos mailed an apology letter to each of the 14,055 customers. Atmos ultimately granted 1,247 extended payment arrangements to customers during the relevant time period.

Between January 28, 2005 and April 7, 2005, the CSD and Atmos received a number of high bill complaints from Atmos customers in Rutherford and Williamson counties. The Authority received a total of 34 complaints regarding the matter, while Atmos received 542

complaints. For each of the high bill complaints received by the CSD or Atmos, Atmos sent a service technician to read and check the customer's meter and meet with the customer in person to discuss the bills in question.

After receiving notice from Atmos of the errors and consumer complaints, the CSD began an investigation and contacted representatives of Atmos to discuss the issue. During these conversations and at subsequent meetings Atmos provided the CSD with information concerning the nature and scope of the problem and the results of the Company's internal investigation. Subsequently, discussions ensued between the CSD and Atmos regarding the steps Atmos would take to ensure compliance with Authority Rules 1220-4-5-.08 and 1220-4-5-.09 which govern the practices of Gas Utility Companies.

TRA Rule 1220-4-5-.08 states:

METER READING SHEETS OR CARDS. The meter reading sheets or cards shall show:

- (a) Customer's name, addresses, and rate schedule.
- (b) Identifying number and/or description of the meter(s).
- (c) Meter readings.
- (d) If the reading has been estimated.
- (e) Any applicable multiplier or constant.

Additionally, Rule 1220-4-5-.09 states:

METER READING INTERVAL. Meters shall be read monthly, except that authority may be obtained from the Authority for reading the meters at other than monthly intervals. As nearly as practicable, utilities shall avoid sending a customer two successive estimated bills.

Lastly, Tenn. Code Ann. § 65-4-120 (2004) states:

Penalty for noncompliance with authority. Any public utility which violates or fails to comply with any lawful order, judgment, finding, rule, or requirement of the authority, shall in the discretion of the authority be subject to a penalty of fifty dollars (\$50) for each day of any such violation or failure, which may be declared due and payable by the authority, upon complaint, and after hearing, and when paid, either voluntarily, or after suit, which may be brought by the authority, shall be placed to the credit of the public utility account.

In an effort to resolve all of the complaints referenced above and ensure company compliance with TRA Rules 1220-4-5-.08 and .09, the CSD and Atmos agree to settle this matter based upon the following acknowledgements and terms subject to approval by the Directors of the TRA:

1. Atmos neither admits nor denies that the above-referenced complaints are true and valid complaints or that its actions constitute violations of Tenn. Comp. R. & Regs. 1220-4-5-.08 and Tenn. Comp. R. & Regs. 1220-4-5-.09. As part of the consideration for this settlement agreement, Atmos has agreed not to contest the complaints.

2. Atmos agrees to make a payment of \$25,000 in settlement of this matter and agrees to remit that amount to the Office of the Chairman of the TRA no later than thirty (30) days following the approval of this Settlement Agreement by the TRA Directors.

3. In addition to the payment set forth in Paragraph 2 above, Atmos agrees to make a \$15,000 contribution, after consultation with the CSD, to community organizations such as Warm Neighbors that assist Murfreesboro area residents in paying their gas bills.

4. Atmos agrees to notify the CSD in advance if it decides to contract out its meter reading function. Atmos agrees to develop heightened procedures to verify the accuracy of meter readings by independent contractors, should it decide to enter into such contracts in the future. Those procedures may include spot audits of readings, having readings periodically verified by Atmos personnel, and rotating the routes read by each meter reader on a periodic basis. Should Atmos decided to utilize independent contractors for meter reading, Atmos agrees to deliver to the TRA, for Authority approval, a written copy of the heightened procedures it proposes to utilize with regard to the independent contractor meter readers before the independent contractors begin the meter reading. Atmos agrees to provide reports reflecting the

independent contractor's compliance with the heightened procedures to the TRA every 6 (six) months during the term of any meter reading contract the Company may enter into in the future.

5. Atmos agrees to comply with all the statutory and regulatory requirements of the TRA, and in the event that Atmos merges or consolidates with or transfers its assets to another firm, corporation or entity, Atmos or its successor shall remain responsible for fully complying with the terms and conditions of the Settlement Agreement. Atmos shall so notify the CSD no less than ten (10) days prior to the completion of such transaction.

6. Atmos agrees that a company representative will attend in person the Authority Conference during which the Directors consider this Settlement Agreement.

7. Compliance with all terms and conditions of this Settlement Agreement by Atmos shall be deemed a full release, accord and satisfaction of all liability for the aforementioned outstanding issues and Atmos shall be excused from further proceedings in this matter.

8. In the event that Atmos fails to comply with the terms and conditions of this Settlement Agreement, the TRA reserves the right to re-open this docket. Atmos shall pay any and all costs incurred by the TRA in the future to enforce compliance with the Settlement Agreement.

9. This Settlement Agreement represents the entire agreement between the parties, and there are no representations, agreements, arrangements or understandings, oral or written, between the parties relating to the subject matter of this Settlement Agreement that are not fully expressed herein or attached hereto

10. If any clause, provision or section of this Settlement Agreement shall, for any reason, be held illegal, invalid or unenforceable, such illegality, invalidity or unenforceability shall not affect any other clause, provision or section of this Settlement Agreement and this

Settlement Agreement shall be construed and enforced as if such illegal, invalid or unenforceable clause, section or other provision had not been contained herein

Eddie Roberson / gdc

Eddie Roberson
Chief, Consumer Services Division
Tennessee Regulatory Authority

June 2, 2005
Date

Misty Smith Kelley

Signature

Misty Smith Kelley

Print Name

Attorney

Print Title

Atmos Energy Corporation

May 31, 2005
Date



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T.R.A. DOCKET ROOM

February 23, 2006

Ron Jones, Chairman
Tennessee Regulatory Authority
460 James Robertson Parkway
Nashville, Tennessee 37243-0505

Re: Formal Notice of Violations
Atmos Energy Corporation – Murfreesboro Incident – August 2, 2005
Report of Natural Gas Safety Inspection #05-267
Docket No. 05-00323

Dear Chairman Jones:

In response to the letter from the Chief of the Gas Pipeline Safety Division accompanying the above-referenced Report, Atmos Energy Corporation's requested an informal conference pursuant to TRA Rule 1220-4-5-.47(6)(a)(3). Informal conferences with gas pipeline safety staff were held on January 10 and February 9, 2006. As a result, Atmos Energy proposes the attached Action Plan which has been reviewed by the staff investigative team.

After a very thorough internal investigation of the event subject of the Report, Atmos Energy has taken, as more particularly described in the Action Plan, a number of appropriate actions based upon the findings of the TRA Natural Gas Safety Inspection Report. These actions are designed to monitor and evaluate the effectiveness of our ongoing safety and operation and maintenance policies and procedures, to improve upon them where applicable and to definitively reassert the importance of personal responsibility in executing assigned job duties per established procedures.

Thank you for your consideration in this matter and please do not hesitate to call me at (615) 771-8320 if you have any questions or require additional information. We request that the TRA approve the Action Plan to resolve this matter.

Sincerely,

A handwritten signature in dark ink, appearing to read "Dan L. Lindsey".

Dan L. Lindsey
Vice President, Technical Services
Mid-States Division

cc: ✓ Glynn Blanton
John Paris
Pat Childers
Jay Carnahan
Doug Walther
John Holloway
Jeff Perryman

**ATMOS ENERGY CORPORATION'S
ACTION PLAN (MURFREESBORO INCIDENT)
NATURAL GAS SAFETY INSPECTION #05-267**

On August 2, 2005, at approximately 8:35 A.M., a release of natural gas occurred at 5410 Sherrington Drive in Murfreesboro, Tennessee, on a two-inch polyethylene distribution main owned and operated by Atmos Energy Corporation (the "Company"). Ignition of the natural gas escaping from the main occurred and resulted in burn injuries to a Company employee, requiring hospitalization. The incident was subsequently investigated by the Tennessee Regulatory Authority (TRA) under the authority of Tennessee Code Annotated §65-28-106. The results of the TRA safety staff's investigation and findings are set forth in TRA's Report of Natural Gas Safety Inspection #05-267 (the "Report").

After receiving the Report, the Company requested an informal conference with TRA safety staff pursuant to TRA Rule 1220-4-5-.47(6)(a)(3) to discuss the issues addressed in the Report. Informal conferences with staff occurred on January 10, 2006, and February 9, 2006, which resulted in the Company's preparation and submission of this Action Plan (the "Plan"). The purpose of this Plan is to outline the action items which the Company has taken and will take to mitigate against the re-occurrence of similar incidents subject of the Report as well as hopefully prevent the occurrence of other incidents.

A. *Action Taken Subsequent to the Incident*

After the occurrence of the incident, the Company promptly took the following steps and actions:

1. Conducted an internal review of the circumstances surrounding the incident for purposes of identifying any process, procedure or training failures. Although the Company was unable to ascertain the exact cause of the ignition of the gas, it was determined that the Company's employees involved in the incident had failed to follow proper procedures contrary to the training which they had received. A "lessons learned" was developed as a result of the internal review which will be incorporated into future employee training and communication materials.
2. Communicated to employees the occurrence of the incident through safety team meetings and re-emphasizing the importance, for both the safety of employees and the public, of observing and complying with the required procedures.
3. Took appropriate employee disciplinary measures and reinforced to all employees that failure to comply with required safety and operating and maintenance procedures will not be tolerated.

4. Organized a workgroup to review existing procedures and training materials and to develop specific procedures manuals which will bridge any perceived gaps between the Company's operations and maintenance manual and its operator qualification training materials.
5. Revising the Company's Tennessee emergency plan to include the step-by-step procedures for responding to natural gas emergencies.

B. Further Action to be Taken

The Company intends to take the following additional action:

1. Periodically address the "lessons learned" with employees during future safety meetings and training for purposes of demonstrating and learning the consequences of failure to comply with required safety and operating and maintenance procedures.
2. Beginning with calendar year 2006, perform a comprehensive safety and operations and maintenance compliance audit of the Company's operations in each of the eleven towns in Tennessee served by the Company. The purpose of each audit will be to verify compliance with safety policies and operating and maintenance procedures. At the end of each calendar quarter, the Company will conduct selected employee meetings in Tennessee to discuss the result of the audits performed during the quarter. TRA safety staff will be invited to attend these meetings and discuss the results with Company employees.
3. Beginning with calendar year 2006, a team composed of a division safety representative and a manager or supervisor will conduct at least two unannounced inspections of Company work sites in each town in Tennessee served by the Company to ensure safety protocol and operation and maintenance procedures are being observed. Any Company employees who are found, as a result of any such inspection, to have failed to comply with applicable safety protocols or operation and maintenance procedures will be subject to appropriate disciplinary action.
4. Re-emphasize the importance of daily work execution with all Company personnel through periodic employee staff and safety meetings.
5. Use best efforts to complete the procedures manuals project by January of 2007. These manuals will contain the step-by-step procedures to be observed and followed by Company employees for all tasks addressed in the Company's operations and maintenance manual. The operations and maintenance manual will be cross-referenced to the applicable procedure in the procedures manuals. The procedures manuals will be kept by all operator

qualified employees at Company work locations for immediate reference. The Company ultimately hopes to have all manuals electronically available to employees on laptop computers kept in their service vehicles. In connection with the roll-out of the procedures manuals, the Company will provide training to all employees who perform operations and maintenance procedures with respect to the location, use of and reference to the manuals.

The Company sincerely regrets the occurrence of the incident and the injuries suffered by one of its employees. Fortunately, the Company's employee who was injured in the incident is well on his way to a full recovery. The Company believes that discussing this incident with employees in safety team meetings will be very effective because they will hear about a real life example of what can happen as a result of failing to comply with and observe safety procedures. The Company appreciates the opportunity to work with the TRA safety staff through this matter and believes that this Plan addresses the violations cited in the Report and provides a roadmap to improving compliance. The Company has worked diligently over the past several years to promote safety awareness and safe work practices by its employees through a dynamic safety culture in which employee participation is fervently advocated. The Company views this Plan as a continuation of the Company's commitment to promote and foster a culture of safety.

The Company agrees to pay the assessment recommended in the Report. Upon the TRA's approval of this Plan, the Company will transmit a check in the amount of \$13,000.00 payable to the TRA.

TENNESSEE REGULATORY AUTHORITY

Ron Jones, Chairman
Deborah Taylor Tate, Director
Pat Miller, Director
Sara Kyle, Director



RECEIVED
2005 DEC - 1
460 James Robertson Parkway
Nashville, Tennessee 37243-0505
T.R.A. DOCKET ROOM

November 28, 2005

UPS Overnight Delivery

Mr. Dan L. Lindsey
Vice President, Technical Services
ATMOS Energy Corporation
810 Crescent Centre Drive
Franklin, Tennessee 37067-6226

05-00323

Re: Formal Notice of Violations
ATMOS Energy Corporation - Murfreesboro Incident - August 2, 2005
Report of Natural Gas Safety Inspection #05-267

Dear Mr. Lindsey:

On August 2, 2005, ATMOS Energy Corporation, in Murfreesboro, Tennessee experienced a rupture of a two-inch natural gas pipeline resulting in ignition of gas and hospitalization of one ATMOS employee. Under the Minimum Federal Safety Standards (MFSS), overnight hospitalization of an individual as the result of a natural gas accident is considered an "incident" and reportable to the Federal Office of Pipeline Safety and the state agency enforcing the MFSS. This incident was investigated by the Tennessee Regulatory Authority (TRA) in accordance with Tennessee Code Annotated (TCA) Section 65-28-106 and Section 60105 (c) (B) of the Natural Gas Safety Act to determine the cause and circumstance of the incident.

As a result of our on-site inspection and extensive investigation, the Gas Pipeline Safety Division has determined that ATMOS Energy Corporation has committed a violation as specified in the attached August 2, 2005 ATMOS Energy Corporation Pipeline Accident Report. Pursuant to TCA Section 65-28-108 (a), ATMOS is subject to a civil penalty not to exceed ten thousand dollars (\$10,000) per day for each violation during the duration of the violation. Considering the cause and circumstances of the incident as determined by our investigation, ATMOS Energy Corporation is hereby assessed a civil penalty of **\$13,000**.

Page 2

Mr. Dan L. Lindsey

November 28, 2005

The Civil Penalty Schedule included in the report sets forth the basis for determining the amount of the civil penalty for each violation.

In accordance with TRA Rule 1220-4-5-.47 (5) & (6), a written response from ATMOS Energy Corporation is to be submitted to the Pipeline Safety chief within thirty (30) days of receipt of this Formal Notice of Violation. Your response options to this requirement are:

1. Submit a written statement to the Pipeline Safety chief indicating that corrective measures have achieved compliance;
2. Submit a written plan of action to the Pipeline Safety chief outlining the corrective measures that will be taken to achieve compliance and when compliance is anticipated; or
3. Request an informal conference with the Pipeline Safety chief to discuss the violation(s).

If you have any questions regarding this matter or wish to schedule an informal conference, please call me at 800.342.8359 extension 185. Thank you for your cooperation and attention in matters relating to gas pipeline safety.

Sincerely,



Glynn Blanton, Chief
Gas Pipeline Safety Division

GB/vnm

Attachment-August 2, 2005 ATMOS Energy Corporation – Murfreesboro
Pipeline Accident Report

TENNESSEE REGULATORY AUTHORITY

Ron Jones, Chairman
Deborah Taylor Tate, Director
Pat Miller, Director
Sara Kyle, Director



460 James Robertson Parkway
Nashville, Tennessee 37243-0505

REPORT OF NATURAL GAS SAFETY INSPECTION #05-267

OPERATOR: Atmos Energy: Murfreesboro -- Murfreesboro, Tennessee

PERSON (S) CONTACTED: Dan Lindsey, Vice President of Technical Services

INSPECTION DATE: 8/03 and 22/05

TRA ENGINEER: Tom Woosley

Any questions pertaining to this report may be directed to the above address or by telephoning (615) 741-2844, extension 181. (Call toll-free within Tennessee at 1-800-342-8359, extension 181.)

1. **PURPOSE OF INSPECTION:** To perform an incident investigation in response to an incident reported on August 2, 2005, by Atmos Energy at 5410 Sherrington Drive, Murfreesboro, Tennessee

2. **VIOLATION (S) OF THE MINIMUM FEDERAL SAFETY STANDARDS:**

A. **Violation(s) Cited this Inspection**

§192.605 Procedural manual for operations, maintenance, and emergencies.

Each operator shall include the following in its operating and maintenance plan

- (a) General Each operator shall prepare and follow for each pipeline, a manual of written procedures for conducting operations and maintenance activities and for emergency response. For transmission lines, the manual must also include procedures for handling abnormal operations. This manual must be reviewed and updated by the operator at intervals not exceeding 15 months, but at least one each calendar year. This manual must be prepared before operations of a pipeline system commence. Appropriate parts of the manual must be kept at locations where operations and maintenance activities are conducted.

§192.615 Emergency plans.

- (a) Each operator shall establish written procedures to minimize the hazard resulting from a gas pipeline emergency. At a minimum, the procedures must provide for the following

- (1) Receiving, identifying, and classifying notices of events which require immediate response by the operator
- (2) Establishing and maintaining adequate means of communication with appropriate fire, police, and other public officials
- (3) Prompt and effective response to a notice of each type of emergency, including the following
 - (i) Gas detected inside or near a building
 - (ii) Fire located near or directly involving a pipeline facility
 - (iii) Explosion occurring near or directly involving a pipeline facility
 - (iv) Natural disaster
- (4) The availability of personnel, equipment, tools, and materials, as needed at the scene of an emergency
- (5) Actions directed toward protecting people first and then property
- (6) Emergency shutdown and pressure reduction in any section of the operator's pipeline system necessary to minimize hazards to life or property
- (7) Making safe any actual or potential hazard to life or property.
- (8) Notifying appropriate fire, police, and other public officials of gas pipeline emergencies and coordinating with them both planned responses and actual responses during an emergency
- (9) Safely restoring any service outage
- (10) Beginning action under §192.617, if applicable, as soon after the end of the emergency as possible.

§192.751 Prevention of accidental ignition.

Each operator shall take steps to minimize the danger of accidental ignition of gas in any structure or area where the presence of gas constitutes a hazard of fire or explosion, including the following

- (a) When a hazardous amount of gas is being vented into open air, each potential source of ignition must be removed from the area and a fire extinguisher must be provided

B. Violation(s) Previously Cited: **None.**

C. Violation(s) Closed this Inspection: **None.**

3. **OBSERVATIONS, COMMENTS, AND RECOMMENDATIONS:** See attached "Pipeline Incident Report"

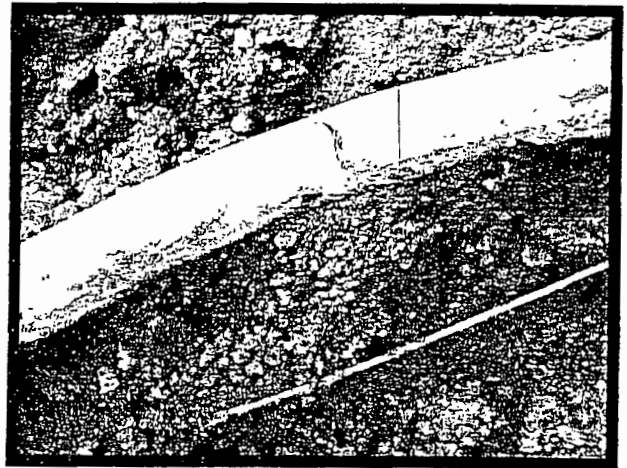
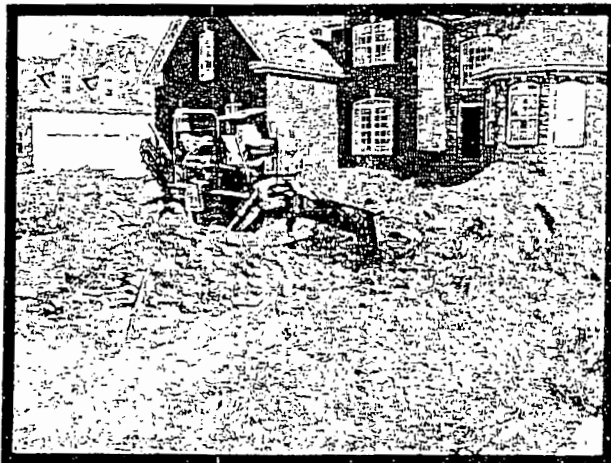
4. **ACTION REQUIRED BY OPERATOR:** Take appropriate action to ensure no recurrence of a similar incident. Provide documentation to this office to substantiate that remedial action has been completed.



TENNESSEE REGULATORY AUTHORITY

PIPELINE INCIDENT REPORT

ATMOS ENERGY
5410 SHERRINGTON DRIVE
MURFREESBORO, TN – AUGUST 2, 2005



REPORT OF NATURAL GAS SAFETY INSPECTION #05-267

Atmos Energy - Murfreesboro August 2, 2005 Incident Report Murfreesboro, Tennessee

Introduction

On August 2, 2005, at approximately 8:35 A.M., a release of natural gas occurred on a two-inch polyethylene distribution main operated by Atmos Energy. The release occurred at 5410 Sherrington Drive, Murfreesboro, Tennessee. Natural gas was ignited and one Atmos Energy (Atmos) employee was transported to Vanderbilt Hospital where he was admitted for burns received in the incident.

This pipeline incident was investigated by the Tennessee Regulatory Authority (TRA) under authority of Tennessee Code Annotated § 65-28-106, by which TRA representatives are authorized to inspect all pipeline systems, facilities and equipment and have the right of access and entry to all buildings and property owned, leased or operated by such systems. Furthermore, the TRA is authorized to enforce federal safety standards and exercise regulatory jurisdiction over the safety of pipeline systems and transportation of gas as set forth in the Natural Gas Pipeline Safety Act of 1968.

Brief Synopsis

On August 2, 2005, Mr. Terry Waldrop and Mr. Greg Mason were assigned the job of installing a new service at the incident address. Mr. Waldrop assembled the riser and meter set while Mr. Mason excavated the trench for the service line. A Ditch Witch model 3610 trencher unit equipped with a backhoe was utilized for this excavation. At approximately 8:00 A.M., Mr. Mason began to excavate at the main for the service tap connection. Mr. Waldrop acted as a spotter while Mr. Mason utilized the backhoe to uncover the natural gas main. When natural gas pipeline warning tape was exposed, Mr. Waldrop signaled to Mr. Mason of its presence. Mr. Mason signaled back that he saw the tape and continued to dig with additional caution with the backhoe. At approximately 8:20 A.M., Mr. Waldrop signaled to Mr. Mason that the top of the main was visible. Mr. Mason acknowledged that he saw the pipe and continued to dig on either side of the main so that a bolt-on tapping tee could be installed. At approximately 8:30 A.M., as Mr. Mason retracted the backhoe boom and rolled the bucket inward, a tooth of the backhoe tore the plastic material and caused the release of natural gas. Mr. Mason attempted to advise Mr. Waldrop of items needed from the truck to repair the natural gas main, but due to the noise of the escaping gas could not communicate to him verbally. Both men went to the truck and obtained the necessary items for the repair. At approximately 8:35 A.M., Mr. Mason remounted the trencher and began removing additional dirt so the repair could be made. Mr. Waldrop heard the trencher engine sputter, after which the entire bell hole burst into flames. Mr. Waldrop ran

toward the truck to avoid the flames. Mr. Waldrop looked back at the trencher and saw that Mr. Mason was still on the machine, attempting to get off but appearing disoriented. Mr. Waldrop ran back to the trencher and pulled Mr. Mason from the machine. He then rolled him on the ground to ensure that his clothes were not burning. Mr. Mason then removed the fire extinguisher from the truck and handed it to Mr. Waldrop. Mr. Waldrop emptied the extinguisher into the burning gas but was unable to extinguish the fire. Mr. Waldrop then called 911 and provided the pertinent information to the dispatcher. As this call was being placed, a nearby homeowner came to the truck and indicated that he had notified 911 of the fire. Mr. Waldrop then attempted to contact the Atmos Murfreesboro office but only reached voicemail. He then called Mr. Dale Collins, Operations Supervisor for the Murfreesboro area, and advised him of the incident. Mr. Collins indicated that he would be there right away. Mr. Collins then contacted the Atmos Energy Central Region office in Franklin, Tennessee. Mr. Dan Lindsey, Atmos Vice President, attempted to contact Glynn Blanton, TRA Gas Pipeline Safety Chief, by phone at approximately 9:37 A.M. Mr. Lindsey left a voicemail message regarding the incident. Mr. Jack Sanders, Atmos Compliance Manager, followed-up with a second phone call at 10:20 A.M. to Mr. Tom Woosley and provided details of the incident (Exhibit One). The Murfreesboro Fire Department and an ambulance arrived and Mr. Waldrop advised the medical personnel of Mr. Mason's need for medical attention. Mr. Waldrop then advised the fire personnel that the incident area was clear of other personnel and instructed them to not put the fire out. Mr. Waldrop then went to check on the condition of Mr. Mason. While with Mr. Mason, Mr. Waldrop observed that the fire department was attempting to put the fire out. Mr. Collins arrived and again instructed the fire department to not attempt to extinguish the fire. The main was supplied from one direction and a single remote bell hole was dug so that the line could be squeezed off to remove the source of fuel to the fire. The damaged section of main was replaced with a new section of pre-tested pipe and placed back in service. Service was restored around 11:30 A.M. Approximately 10 customers were without service while repairs were being completed. Medical treatment was given to Mr. Mason onsite until a helicopter arrived to transport him to Vanderbilt Hospital.

Investigation

On August 3, 2005, Mr. Tom Woosley of the Tennessee Regulatory Authority, Gas Pipeline Safety Division, met with Atmos staff members at the Murfreesboro office to review this incident. A complete listing of those in attendance is included as Exhibit Nine attached to this report. Mr. Waldrop attended the meeting and provided a written account of events associated with the incident. This account explained in excellent detail the events leading to and following the incident. Photographs of the incident site, taken by Mr. Dale Collins, were provided as evidence (Exhibits 3-7). The photographs included a variety of views of the site and damages that had occurred. Mr. Sanders provided a listing of covered tasks that Mr. Mason and Mr. Waldrop had been qualified to perform (Exhibit Ten). This listing includes the reevaluation interval for all tasks and the expiration date for each current qualification. In addition, evaluation forms were obtained for the tasks "Excavation Damage Prevention," and "Preventing Accidental Ignition" (Exhibit Eleven). These forms indicate the basic requirements for

qualification in each task. This information was taken back to the Gas Safety office for a thorough review.

On August 22, 2005, Mr. Woosley met again at the Murfreesboro area office to obtain additional information related to the incident. Specifically of interest were procedures utilized during the service installation and emergency procedures associated with the gas release and the fire that resulted. Mr. Dale Collins, Mr. Steve Bittel, Mr. Jack Sanders, and Mr. Jay Murray were in attendance for this meeting. The United Cities (Atmos) Operation and Maintenance plan, Construction Procedures, and Emergency Procedures were reviewed for procedures specific to performance of the work which led to this incident. Particularly of interest were procedures relating to the excavation of the main and prevention of ignition. Atmos provided a copy of the Emergency Operating Procedures (Exhibit Thirteen), Operator Qualification (OQ) training modules "Preventing Accidental Ignition" (OQ M-8, Exhibit Fourteen), "Responding to a Natural Gas Emergency" (OQ M-13, Exhibit Sixteen), and "Identifying Excavation Damage Prevention Practices" (OQ M-14, Exhibit Fifteen). When no specific procedures could be found in the Emergency Operating Procedures or Operation and Maintenance Plan relating to the service installation and uncontrollable release of gas, Mr. Sanders and Mr. Bittel indicated that the training modules provided more detail in how these covered tasks were to be performed.

In addition to collecting these materials, there was a discussion regarding follow-up action under the OQ and emergency plans. Mr. Sanders and Mr. Bittel indicated that Mr. Waldrop and Mr. Mason will be reevaluated for all tasks associated with the job they were performing. In addition, the incident will be reviewed to develop "lessons learned" and determine if the OQ program or emergency plans require modification.

Analysis

After meeting with Atmos personnel and reviewing Mr. Waldrop's account of the incident, the Operation and Maintenance Plan, the Emergency Operating Procedures, and the provided Operator Qualification student modules, the following observations were developed:

- ♦ The damage to the polyethylene main indicates that a safe clearance was not maintained between the backhoe bucket and the main. OQ M-14 (Exhibit Fifteen) provides guidance on page 6 under "Excavation Practices Used to Avoid Damage." Specifically it states to "Maintain a safe clearance between the underground facilities and the cutting edge of any mechanized equipment, taking into account the known limit of control of the cutting edge, to avoid damage to facilities."
- ♦ The damage to the line by the backhoe bucket also indicates that hand digging was not performed within the tolerance zone as described on page 6 of OQ M-14 (Exhibit Fifteen). Again under the heading "Excavation Practices Used to Avoid Damage," several recommendations are listed in regard to hand digging: "Dig by hand inside the tolerance zone." "Usually an excavation within the location tolerance zone must

be performed with hand tools until the marked facility is exposed” “The hand digging zone is 18” each side of the width of the facility, as illustrated in figure 2”

- ◆ After the main was damaged and gas was being released, additional digging was performed with the backhoe to expose the damaged main for repair. This maintained an ignition source in close proximity to a hazardous atmosphere. OQ M-8 states on page 26 that “Internal combustion engines that power trucks, cars, compressors, pumps, generators and other equipment should not be operated in suspected or known hazardous atmospheres.” In addition, the uncontrolled release of gas from a plastic pipeline provided an additional potential source of ignition from static electricity. On pages 26 of OQ M-8 (Exhibit Fourteen), static electricity is recognized as a possible ignition source and thus a potential hazard. On page 28 of the same training material a procedure is described which requires digging remote bell holes to squeeze off a damaged plastic main for repair. Since none of these precautions were followed, it appears that the potential hazard of ignition was not recognized or was ignored altogether.
- ◆ On page 5 of OQ M-13 (Exhibit Sixteen) the training material states “If there is the likelihood of fire or explosion from leaking gas, local emergency response agencies will be put on notice immediately.” Notification was made after ignition occurred but no notification was made prior to ignition of the gas of the pending emergency created by the uncontrolled release of gas.
- ◆ The Operator Qualification Knowledge, Skills, and Ability Evaluation Form (Exhibit Eleven) for the task “Preventing Accidental Ignition” indicates that “Uncontrolled escaping natural gas” is an abnormal operating condition. The prescribed reaction to this is “Follow Emergency Operating Procedures.” After reviewing the Emergency Operating Procedures it is unclear what section of the plan would apply to uncontrolled release of gas and more specifically what course of action should be followed.
- ◆ Emergency Operating Procedures (Exhibit Thirteen) provide generalized actions to follow but no specific procedures. Operator qualification training materials should reiterate procedures established in the Emergency Operating and Operation & Maintenance plans. None of the specific procedures referenced from OQ training materials in bulleted items above appear in either plan.
- ◆ Operator qualification records (Exhibit Ten) for Mr. Mason do not include qualification for Emergency Response. Mr. Waldrop was qualified in January of 2005 for this task. Mr. Sanders noted this oversight and ensured that it would be corrected.

Conclusions

This incident appears to have been avoidable and the result of operator error. The damage to the polyethylene main and resulting release of natural gas would likely not have occurred if the excavation had been performed by hand instead of utilizing the backhoe.

There is no indisputable proof of the ignition source in this incident. Since the main was polyethylene, a static electric discharge cannot be ruled out. Mr. Waldron's description of the trencher engine sputtering prior to the ignition lends to the possibility that natural gas was in the vicinity of the trencher and was being pulled into the air intake of its engine. Any one of a number of electrical spark sources on the engine could have ignited the gas.

Regardless of what may have served as the ignition source, excavation should not have continued with the trencher in close proximity to the uncontrolled release of natural gas. The damaged section of main could have been isolated through the use of valves or squeezed off to safely make the repair as recommended in operator qualification training materials. Section 192.751(a) of Minimum Federal Safety Standards (MFSS) requires that all ignition sources be removed from the area when the presence of gas constitutes a hazard of fire or explosion. Continued use of the trencher to excavate the main while gas was being released is a direct violation of this requirement. **Operator is cited in violation of §192.751(a) for failing to remove ignition sources from an area where a hazardous atmosphere existed**

The Knowledge, Skills and Ability Evaluation form utilized by Atmos indicates that uncontrolled escaping gas is an abnormal operating condition under the task "Preventing Accidental Ignition." The reaction indicated for uncontrolled escaping gas is to follow the Emergency Operating Procedures. During the review of Emergency Operating Procedures no specific procedures were found addressing uncontrollable release of gas. An employee who went to this plan for guidance would be at a loss to determine the proper course of action to follow. By definition a written procedure is a written series of steps followed in a regular definite order. The written procedures should provide enough direction that an employee could refer to the plan for guidance. While the Emergency Operating Procedures and the Operation and Maintenance Plan address by topic most of the items required by MFSS, they do not reflect the procedures included in operator qualification training. If these procedures are the expected course of actions for every day operation, maintenance, and emergency response, then these procedures should be incorporated into both written plans. The training materials used in the operator qualification program appear to present much more detailed procedures than any portion of the Emergency Operating Procedures or Operation and Maintenance Procedures. Section 192.615(a) states: "Each operator shall establish written procedures to minimize the hazard resulting from a gas pipeline emergency." Section 192.605(a) states "Each operator shall prepare and follow for each pipeline, a manual of written procedures for conducting operations and maintenance activities and for emergency response." While these plans may address some or all areas required by MFSS, they do not mirror the procedures that are taught employees to use in performing their assigned tasks and on which their operator qualification is based. **Since these plans do not include all procedures for everyday operation, maintenance, and**

emergency response they are inadequate and for this reason violations of §192.605(a) and §192.615(a) are cited at this time

EXHIBITS

Index of Exhibits

Exhibit One	Incident Report filed with Tennessee Regulatory Authority.
Exhibit Two	Incident Report filed with Federal Department of Transportation. (three pages)
Exhibit Three	Photograph – View of trencher from Sherrington Drive.
Exhibit Four	Photograph – View of trencher from 5410 Sherrington Drive
Exhibit Five	Photograph – Close-up of back-hoe bucket following incident
Exhibit Six	Photograph – Damaged section of two-inch natural gas main.
Exhibit Seven	Photograph – Close-up of damaged natural gas main.
Exhibit Eight	Incident account of Terry Waldrop. (four pages)
Exhibit Nine	Attendee list of August 3, 2005 incident review meeting. (two pages)
Exhibit Ten	Listing of qualified tasks for Greg Mason and Terry Waldrop (two pages)
Exhibit Eleven	KSA evaluation forms for Excavation Damage Prevention and Preventing Accidental Ignition (two pages)
Exhibit Twelve	Verification from Tennessee One-Call of locate ticket
Exhibit Thirteen	Atmos Energy Emergency Operating Procedures.
Exhibit Fourteen	Atmos Energy student manual – GDS 11, (OQ M-8) Preventing Accidental Ignition
Exhibit Fifteen	Atmos Energy student manual – GDS 79, (OQ M-14) Identifying Excavation Damage Prevention Practices
Exhibit Sixteen	Atmos Energy student manual – GDS 28, (OQ M-13) Responding to a Natural Gas Emergency
Exhibit Seventeen	Newspaper article from Murfreesboro Daily News Journal.
Exhibit Eighteen	Civil Penalty Schedule. (four pages)

Exhibit One

TELEPHONIC ACCIDENT REPORT
Section 191.5 MFSS

Date of Call 8-2-05 Time 10:20 AM

Person Calling to Report Incident Jack Sanders

Name of Gas System Atmos Energy - Montreesboro

Incident information:

Date 8-2-05 Time 9:30 AM

Location ~~5010 Berkman Dr~~ 5410 Sherrington

Personal Injuries ☒ Yes ☐ No Number 1

Did personal injuries require hospitalization? ☒ Yes ☐ No

Fatalities ☐ Yes ☒ No

Details of Personal Injuries and/or Fatalities Burns to arms

Property Damage ☒ Yes ☐ No

Does amount of property damage to operators and/or others
property exceed \$5,000? ☒ Yes ☐ No

Details of Property Damage Trencher destroyed
by fire

Probable Cause Struck main with trencher

Did the incident require the taking of any segment of transmission pipe-
line out of service? ☐ Yes ☒ No

Did the incident result in gas igniting? ☒ Yes ☐ No

Other information Flash fire burned employee

Has Washington been called? ☒ Yes ☐ No

Washington telephone number - (800) 424-8802

Signature of person completing this form:

Sam W. Wesley

Exhibit Two

OPTIONAL FORM 89 (7-90)

FAX TRANSMITTAL

of pages = 3

To <i>TRA</i>	From <i>OPR-AD</i>
Dept/Agency <i>GC Safety</i>	Phone #
Fax #	Fax #
NSN 7540-0 -317-7368 5099-101 GENERAL SERVICES ADMINISTRATION	

OPS Accident/Incident Cadre <PHMSA>
ation pipeline, one injury that required hospitalization

-----Original Message-----

From fldr-NRC@comdt.uscg.mil [mailto:fldr-NRC@comdt.uscg.mil]
Sent Tuesday, August 02, 2005 12 03 PM
To OPS Accident/Incident Cadre <PHMSA>, cmc-01@rspa.dot.gov
Subject NRC#767650

NATIONAL RESPONSE CENTER - FLASH FAX
GOVERNMENT USE ONLYGOVERNMENT USE ONLY***
DO NOT RELEASE this information to the public without
permission from the NATIONAL RESPONSE CENTER 1-800-424-8802

Incident Report # 767650

INCIDENT DESCRIPTION

*Report taken by CIV JOHNSON at 11 54 on 02-AUG-05
Incident Type: PIPELINE
Incident Cause OPERATOR ERROR
Affected Area.
The incident occurred on 02-AUG-05 at 08 30 local time
Affected Medium AIR ATMOSPHERE

REPORTING PARTY

Name JACK SANDERS
Organization ATMOS ENERGY
Address 810 CRESCENT CENTRE DR >
SUITE 600
FRANKLIN, TN 37067
ATMOS ENERGY called for the responsible party
PRIMARY Phone (615)7718387 ALTERNATE Phone (615)3107985
Type of Organization PUBLIC UTILITY

SUSPECTED RESPONSIBLE PARTY

Name JACK SANDERS
Organization ATMOS ENERGY
Address 810 CRESCENT CENTRE DR >
SUITE 600
FRANKLIN, TN 37067
PRIMARY Phone (615)7718387 ALTERNATE Phone (615)3107985
Type of Organization PUBLIC UTILITY

INCIDENT LOCATION

5010 BURKSHIRE DR County RUTHERFORD
City MURFREESBORO State TN

RELEASED MATERIAL(S)

CHRIS Code ONG Official Material Name NATURAL GAS
Also Known As.
Qty Released 0 UNKNOWN AMOUNT

DESCRIPTION OF INCIDENT

NATURAL GAS RELEASED FROM A 2" MAIN LINE DUE TO OPERATOR STRUCK LINE

WITH A PIECE OF EQUIPMENT.

INCIDENT DETAILS

Pipeline Type DISTRIBUTION
DOT Regulated YES
Pipeline Above/Below Ground: BELOW
Exposed or Under Water. NO
Pipeline Covered UNKNOWN

DAMAGES

Fire Involved YES Fire Extinguished YES
INJURIES 1 Hospitalized: 1 Empl/Crew: Passenger:
FATALITIES Empl/Crew Passenger Occupant
EVACUATIONS: Who Evacuated Radius/Area:
Damages

Closure Type	Description of Closure	Hours Closed	Direction of Closure
Air	N		
Road	N		Major N Artery
Waterway	N		
Track	N		

Passengers Transferred UNKNOWN
Media Interest NONE Community Impact due to Material NO

REMEDIAL ACTIONS

SECURED THE AREA; MAKING REPAIRS ON THE LINE
Release Secured YES
Release Rate.
Estimated Release Duration

WEATHER

Weather. PARTLY CLOUDY, °F

ADDITIONAL AGENCIES NOTIFIED

Federal.
State/Local: TN REGULATORY AUTHORITY
State/Local On Scene.
State Agency Number NO REPORT #

NOTIFICATIONS BY NRC

DOT CRISIS MANAGEMENT CENTER (PRIMARY)
02-AUG-05 12.01 (202)3661863
U S. EPA IV (PRIMARY)
(404)6504955
NATIONAL INFRASTRUCTURE COORD CTR (PRIMARY)
02-AUG-05 12 01 (202)2829201
NOAA 1ST CLASS BB RPTS FOR TN (PRIMARY)
02-AUG-05 12.01 (206)5266344
NATIONAL RESPONSE CENTER HQ (PRIMARY)
(202)2672100
RSPA OFFICE OF PIPELINE SAFETY (PRIMARY)
TN EMERGENCY RESPONSE (PRIMARY)
02-AUG-05 12 01 (615)7410001
STEVE SPURLIN EPAIV (STEVE SPURLIN EPAIV)
02-AUG-05 12:01

ADDITIONAL INFORMATION

CALLER STATED THAT AN EMPLOYEE WAS INJURED AND TRANSPORTED TO THE
HOSPITAL THE INCIDENT OCCURRED BETWEEN 0830 - 0930.

*** END INCIDENT REPORT 767650 ***

Report any problems or Fax number changes by calling 1-800-424-8802
PLEASE VISIT OUR WEB SITE AT <http://www.nrc.uscg.mil>

Exhibit Three

8/2/05

5410
WENT TO ~~SEE~~ SHERINGTON Dr. IN BIRKSHIRE SUB-DIV
TO RUN A 1/2" SERVICE LINE TO ABOVE ADDRESS. GREG
UNLOADED TRENCHER & BEGAN TO TRENCH FROM THE HOUSE
TO THE MAIN WHILE I GOT THE 1/2" RISER & METER WOP
READY TO INSTALL. GREG MADE THE TRENCH & WAS NEARING
THE 2" POLY MAIN TO PREPARE TO DIG IT UP. I PLACED
THE RISER, TRACER WIRE, & 1/2" SERVICE LINE IN TRENCH
& ROLLED OUT THE 1/2" PIPE TO WHERE GREG WAS LOCATED
AT THE MAIN. GREG SET UP TO DIG UP THE MAIN SHORTLY
AFTER 8:00 AM. DIGGING WAS ROUTINE WITH GOOD
DIRT & VERY LITTLE ROCK. AS GREG DUG I STOOD DIRECTLY
~~ROD~~ ACROSS FROM HIM WHILE HE OPERATED THE
TRENCHER TO ACT AS A SPOTTER WHILE HE DUG FOR
THE MAIN. AS HE DUG WARNING TAPE WAS EXPOSED
& I RAISED MY HAND TO INDICATE IT TO GREG.

HE ACKNOWLEDGED HE COULD SEE THE TAPE
AND SLOWED DOWN HIS DIGGING. APPROX 8:20 AM
THE 2" MAIN WAS EXPOSED ENOUGH TO SEE THE TOP
OF IT. I AGAIN RAISED MY HAND & GREG INDICATED
HE TOO COULD SEE THE PIPE. DIGGING CONTINUED
ON BOTH SIDES OF THE MAIN SO WE COULD INSTALL
THE 2" SADDLE FOR THE SERVICE. GREG BEGAN TO WORK
ON BOTH SIDES OF THE MAIN TO CLEAN THE HOLE OUT
FOR US TO ^{WORK} IN. AROUND 8:30 AM GREG ^{EXTENDED} ~~REMOVED~~ THE
TRENCHER BUCKET TO THE SIDE OF THE 2" POLY

TO CLEAN THE UNDERWEATH SIDE OF THE MAIN
OUT, ON HIS ATTEMPT TO PULL THE BUCKET BACK
AND OUT OF THE HOLE A TOOTH ON THE BUCKET
STRUCK THE UNDERSIDE OF THE MAIN, RELEASING
GAS, GREG BEGAN TO ADVISE ME OF WHAT TO GET
IN ORDER TO MAKE A REPAIR ON THE LINE, UNABLE
TO HEAR DUE TO THE NOISE, GREG GOT OFF THE
TRENCHER + HE + I BOTH WENT TO THE TRUCK WHERE
WE GOT ② SQUEEZE OFF CLAMPS + ONE 2" REPAIR
COUPLING, I Laid THE SQUEEZE OFFS + COUPLING
NEAR THE HOLE AS GREG GOT BACK ON THE TRENCHER,
CLOSE TO 8:35 GREG BEGAN TO REMOVE DIRT FROM
THE HOLE TO MAKE THE REPAIR, I WAS STANDING
IN FRONT FACING GREG WHEN I NOTICED THE TRENCHER
ENGINE SPOTTER, ~~AND~~ AND THEN HEARD A ROAR
FROM THE HOLE, AT THAT TIME THE ENTIRE ~~WALL~~ HOLE
BURST INTO FLAME, AND HAD MADE IT TO THE TRENCHER
WHERE GREG WAS AT, I RAN AROUND THE HOLE TOWARD
THE STREET + CRAW TRUCK, TO AVOID THE FLAMES AND
SEE WHERE GREG HAD GONE. WHEN I LOOKED TOWARD
THE TRENCHER I COULD SEE GREG WAS TRYING TO
STAND UP AND JUMP FROM THE TRENCHER, I RAN
TO HIM ^{AND} ~~REACHED~~ REACHED UP GRABING HIM FROM
THE TRENCHER AND THREW HIM TO THE GROUND
ROLLING HIM TO MAKE SURE HIS CLOTHES WERE
NOT ON FIRE, GREG JUMPED UP AND YELLED
TO GET THE FIRE EXT, FROM THE TRUCK, HE
CLIMBED INTO THE TRUCK BED AND HANDLED

IT TO ME. I WENT BACK TO THE FIRE & EMPTIED THE EXT. BUT COULDN'T PUT THE FIRE OUT. AS I LOOKED FOR GREG I COULD HEAR HIM MOANING IN PAIN.

HE THEN THREW HIS PHONE TO ME AND SAID CALL 911. NOT KNOWING HOW TO UNLOCK & WORK HIS PHONE I HANDED IT BACK FOR HIM TO UNLOCK.

AFTER HE UNLOCKED IT I WAS DIALING 911 AGAIN WHEN A MAN FROM DOWN THE STREET CAME UP & SAID HE SAW THE FIRE & SAID HE HAD ALSO CALLED 911. DURING THAT TIME I TOO WAS ON THE PHONE TO A 911 OPERATOR & TOLD HER WHERE WE WERE THAT WE HAD HIT A GAS LINE THAT WAS NOW ON FIRE & THERE WAS ONE INJURY INVOLVED, THEN SHE HUNG UP.

GREG TOLD ME TO CALL KENDRA AT THE OFFICE BUT WHEN I CALLED I GOT HER VOICE MAIL. GREG THEN SAID TO CALL DALE. I REACHED DALE & TOLD HIM WHAT HAD HAPPENED & HE SAID HE WOULD BE THERE RIGHT AWAY. AFTER TALKING TO DALE THE MURFREESBORO FIRE DEPT & AMBULANCE ARRIVED ON SCENE. I POINTED OUT TO THE MEDICAL STAFF WHERE GREG WAS & THEN WENT OVER TO THE FIRE DEPT.

I TOLD THEM THAT EVERYONE WAS AWAY FROM THE SCENE AND NOT TO PUT THE FIRE OUT. I THEN WENT BACK TO GREG & WHILE WITH HIM THE FIRE DEPT. TRIED TO PUT THE FIRE OUT. AT THAT POINT I NOTICED DALE

GIVING DIRECT ORDERS AGAIN NOT TO PUT WATER
ON THE TRENCHER OR THE HOLE. SHORTLY AFTER THAT
DALE & ANOTHER COMPANY CREW BEGAN TO DIG A
REMOTE HOLE TO SHUT DOWN THE GAS AND PUT
OUT THE FIRE. TREATMENT WAS STARTED ON GREG
AND AN AIR-EVAC HELICOPTER WAS BROUGHT IN
FOR HIS TRANSPORT TO NASHVILLE.

Exhibit Nine

ATTENDEE LIST
Incident Review
Atmos Energy - Murfreesboro
August 3, 2005

<u>Name</u>	<u>Title</u>
Terry Waldrop	Operation Specialist
Glen Deon Scott	Engineering Tech
Dale Collins	Operations Supervisor
Jimmie Tullis	Employee Development/Safety Coordinator
Steve Bittel	Safety Manager
Jack Sanders	Compliance Manager
David Swain	Operations Manager

TERRY WALDROP

OPERATION SPECIALIST

Glen Dean Scott

Engineering Tech

Aale Collins

Operations Supervisor

Jimmie Tullis

Employee Development / Safety Coord.

Steve Bittel

Safety Manager

Jack Sanders - Compliance Manager

DAVID SWAIN - OPERATIONS MANAGER

Exhibit Ten

Job Name	Qualification	Qual Expir Evaluator	Last Taken	Expiry Date	Qualification Method
12539 Sr Construction Operator	Locating and Marking Lines	60 McNeal, John L	10-Feb-03	10-Feb-08	Simulation
12539 Sr Construction Operator	Joining of Polyethylene Pipe with Mechanical Coupling (1 1/4" and 2" IPS)	60 McNeal, John L	10-Feb-03	10-Feb-08	Simulation
12539 Sr Construction Operator	Joining of Polyethylene Pipe with Mechanical Coupling (Bolt Style)	60 McNeal, John L	10-Feb-03	10-Feb-08	Simulation
12539 Sr Construction Operator	Abandoning/Deactivating Gas Pipelines	60 McNeal, John L	10-Feb-03	10-Feb-08	Simulation
12539 Sr Construction Operator	Purging Pipelines	60 McNeal, John L	10-Feb-03	10-Feb-08	Simulation
12539 Sr Construction Operator	Testing Service Lines	60 McNeal, John L	10-Feb-03	10-Feb-08	Simulation
12539 Sr Construction Operator	Inspecting and Repairing Pipe Coating	60 McNeal, John L	10-Feb-03	10-Feb-08	Simulation
12539 Sr Construction Operator	Installing Meters	60 McNeal, John L	10-Feb-03	10-Feb-08	Simulation
12539 Sr Construction Operator	Installing Regulators	60 McNeal, John L	10-Feb-03	10-Feb-08	Simulation
12539 Sr Construction Operator	Installing/Replacing Service Valves	60 McNeal, John L	10-Feb-03	10-Feb-08	Simulation
12539 Sr Construction Operator	Joining of Polyethylene Pipe with Mechanical Tapping Tee (1 1/2" - 2" IPS)	60 McNeal, John L	10-Feb-03	10-Feb-08	Simulation
12539 Sr Construction Operator	Surveying Leaks	60 McNeal, John L	11-Aug-02	11-Aug-07	Simulation
12539 Sr Construction Operator	Performing Valve Maintenance	60 Freeman, Mark S	14-Aug-02	14-Aug-07	Observation
12539 Sr Construction Operator	Internal Corrosion Control	60 Freeman, Mark S	14-Aug-02	14-Aug-07	Observation
12539 Sr Construction Operator	Testing Mains and Transmission Lines	60 Freeman, Mark S	14-Aug-02	14-Aug-07	Simulation
12539 Sr Construction Operator	Conducting Pipe to Soil Measurements	60 Freeman, Mark S	14-Aug-02	14-Aug-07	Simulation
12539 Sr Construction Operator	Installing CP Test Leads to Pipe	60 Freeman, Mark S	14-Aug-02	14-Aug-07	Simulation
12539 Sr Construction Operator	Joining of Polyethylene with Compression type coupling	60 McNeal, John L	14-Aug-02	14-Aug-07	Simulation
12539 Sr Construction Operator	Joining of Polyethylene Pipe with mechanical Coupling (1/2" CTS through 1" IPS)	60 McNeal, John L	14-Aug-02	14-Aug-07	Simulation
12539 Sr Construction Operator	Installing Service Lines	60 McNeal, John L	14-Aug-02	14-Aug-07	Simulation
12539 Sr Construction Operator	Conducting Pipeline Patrolling Surveys	60 Freeman, Mark S	14-Aug-02	14-Aug-07	Simulation
12539 Sr Construction Operator	Installing Cathodic Protection	60 McNeal, John L	14-Aug-02	14-Aug-07	Simulation
12539 Sr Construction Operator	Tapping Pipelines Under Pressure	60 Freeman, Mark S	21-Aug-02	21-Aug-07	Simulation
12539 Sr Construction Operator	Joining of Polyethylene Pipe with Electrofusion (Saddle fusion)	60 McMullin, Jeffery	21-Aug-02	21-Aug-07	Simulation
12539 Sr Construction Operator	Excavation Damage Prevention	12 Ring, Allen	26-Apr-05	26-Apr-08	Test & Observation
12539 Sr Construction Operator	Joining of Polyethylene Pipe with Mechanical Tapping Tee (1 1/2" - 2" IPS)	12 Todd, Samuel T (Tommy)	26-Apr-05	26-Apr-08	Test & Simulation
12539 Sr Construction Operator	Joining of Polyethylene with Compression type coupling	12 Todd, Samuel T (Tommy)	26-Apr-05	26-Apr-08	Test & Simulation
12539 Sr Construction Operator	Joining of Polyethylene Pipe with mechanical Coupling (1/2" CTS through 1" IPS)	12 Todd, Samuel T (Tommy)	26-Apr-05	26-Apr-08	Test & Simulation
12539 Sr Construction Operator	Joining of Polyethylene Pipe with Electrofusion (Coupling fusion)	12 Todd, Samuel T (Tommy)	26-Apr-05	26-Apr-08	Test & Simulation
12539 Sr Construction Operator	Joining of Polyethylene Pipe with Heat fusion (Bolt fusion)	12 Ring, Allen	26-Apr-05	26-Apr-08	Test & Observation
12539 Sr Construction Operator	Preventing Accidental Ignition	12 Ring, Allen	26-Apr-05	26-Apr-08	Test & Observation
12539 Sr Construction Operator		36 Ring, Allen	26-Apr-05	26-Apr-08	Test & Simulation

Employee Operator Qualifications

Cost Emer-MDST-Central South-Subreg Admin (3351) Emp Name Waldrop, Terry A

Emp Num	Job Name	Qualification	Qual Expir Evaluator	Last Taken	Expiry Date	Qualification Method
12560	Operations Specialist	Locating and Marking Lines	36 Snider, Ronald D	18-Feb-02	18-Feb-05	Observation
12560	Operations Specialist	Installing Meters	36 Snider, Ronald D	18-Feb-02	18-Feb-05	Observation
12560	Operations Specialist	Performing Valve Maintenance	36 Ellagood, Robert A	18-Feb-02	18-Feb-05	Simulation
12560	Operations Specialist	Inspecting and testing pressure limiting, telemetering or recording gauges and relief valves	36 Ellagood, Robert A	18-Feb-02	18-Feb-05	Simulation
12560	Operations Specialist	Installing Regulators	36 Snider, Ronald D	18-Feb-02	18-Feb-05	Simulation
12560	Operations Specialist	Perform Oozonization Test	38 Snider, Ronald D	18-Feb-02	18-Feb-05	Observation
12560	Operations Specialist	Atmospheric Corrosion	38 Snider, Ronald D	18-Feb-02	18-Feb-05	Simulation
12560	Operations Specialist	Preventing Accidental Ignition	36 Snider, Ronald D	18-Feb-02	18-Feb-05	Simulation
12560	Operations Specialist	Surveying Leaks	36 Hichcock, Elbert L	20-Apr-05	20-Apr-08	Test & Observation
12560	Operations Specialist	Internal Corrosion Control	36 Triplett, Loyd L	20-Feb-02	20-Feb-05	Simulation
12560	Operations Specialist	Emergency Response	36 Snider, Ronald D	28-Jan-05	28-Jan-08	Test & Simulation
12560	Operations Specialist	Leak Classification	36 Snider, Ronald D	28-Jan-05	28-Jan-08	Test & Simulation
12560	Operations Specialist	Internal Corrosion Control	36 Snider, Ronald D	28-Jan-05	28-Jan-08	Test & Simulation
12560	Operations Specialist	Atmospheric Corrosion	36 Snider, Ronald D	28-Jan-05	28-Jan-08	Test & Simulation
12560	Operations Specialist	Locating and Marking Lines	36 Snider, Ronald D	28-Jan-05	28-Jan-08	Test & Observation
12560	Operations Specialist	Inspecting and testing pressure limiting, telemetering or recording gauges and relief valves	36 Snider, Ronald D	28-Jan-05	28-Jan-08	Test & Simulation
12560	Operations Specialist	Preventing Accidental Ignition	36 Snider, Ronald D	28-Jan-05	28-Jan-08	Test & Simulation
12560	Operations Specialist	Monitoring Regulators	36 Snider, Ronald D	28-Jan-05	28-Jan-08	Test & Simulation
12560	Operations Specialist	Installing Regulators	36 Snider, Ronald D	28-Jan-05	28-Jan-08	Test & Observation
12560	Operations Specialist	Installing Meters	36 Snider, Ronald D	28-Jan-05	28-Jan-08	Test & Observation
12560	Operations Specialist	Surveying Leaks	36 Snider, Ronald D	28-Jan-05	28-Jan-08	Test & Observation
12560	Operations Specialist	Conducting Pipe to Soil Measurements	36 Snider, Ronald D	28-Jan-05	28-Jan-08	Test & Observation
12560	Operations Specialist	Excavation Damage Prevention	36 Snider, Ronald D	28-Jan-05	28-Jan-08	Test & Simulation
12560	Operations Specialist	Performing Valve Maintenance	36 Snider, Ronald D	28-Jan-05	28-Jan-08	Test & Simulation
12560	Operations Specialist	Conducting Pipeline Patrolling Surveys	36 Snider, Ronald D	28-Jan-05	28-Jan-08	Test & Simulation
12560	Operations Specialist	Inspecting and Repairing Pipe Coating	36 Snider, Ronald D	29-Aug-03	29-Aug-06	Simulation

Exhibit Eleven



Operator Qualification Knowledge, Skills and Ability Evaluation Form

Qualification Task: M8, Preventing Accidental Ignition

Re-evaluation Interval: 36 months **Span of Control Ratio:** 1:1

Reference: 192 751

I verify that ~~(Please Print)~~ _____, employee # _____, has successfully completed the preliminary knowledge assessments for this OQ Task by one of the following

____ Online Testing

____ Training

Supervisor Signature _____ Date _____



Abnormal Operating Conditions

(Not limited to the examples listed below)

Recognize

React

- Uncontrolled escaping natural gas

- Follow Emergency Procedures

- Verified that worker avoided entering a bell hole where uncontrolled gas is flowing from a gas line.
- Verified if purging of gas was minimized in bell holes
- Verified worker was equipped with and utilized proper safety equipment.
- Verified that a fire extinguisher was positioned upwind from the excavation.
- Verified that anti-static solution was utilized and continuously used on exposed pipe and surrounding soil
- Verified anti-static film was wrapped over pipe.
- Verified that tools are properly grounded.
- Verified when pipe is cut that an anti-static application was used.

Check Method of Evaluation Used:

____ Simulation

____ Observation

____ Qualified

____ Not Qualified

Evaluator's Name: _____

Evaluator's Signature: _____ Date: _____

Individual Signature: _____

Paper flow process

Qualified:

Original form to the Individual's Supervisor

Request Supervisor to provide copy to individual

Keep a copy for yourself to be used to enter into the record keeping system

Not Qualified

Original form to the Individual's Supervisor

Revised 6-16-04

EXHIBIT 11



Operator Qualification Knowledge, Skills and Ability Evaluation Form

Qualification Task: M14, Excavation Damage Prevention

Re-evaluation Interval: 36 months **Span of Control Ratio:** 11

Reference: 192.614

I verify that (Please Print) _____, employee # _____, has successfully completed the preliminary knowledge assessments for this OQ Task by one of the following

____ Online Testing

____ Training

Supervisor Signature _____ Date _____



Abnormal Operating Conditions
(Not limited to the examples listed below)

Recognize

React

• Indications of a Presence of non-located Buried Facilities	• Call One-Call and/or Excavate with Caution
• Damage to Buried Facilities	• Notify Supervisor and Owner

- Is aware of One-Call requirements.
- Verified foreign facilities are located prior to excavating.
- Knows how to operate Power Operated Excavation Equipment
- Knows line locating color codes.
- Can read and interpret appropriate maps

Check Method of Evaluation Used:

____ Simulation

____ Observation

____ Qualified

____ Not Qualified

Evaluator's Name: _____

Evaluator's Signature: _____ Date: _____

Individual Signature: _____

Paper flow process

Qualified

Original form to the Individual's Supervisor

Request Supervisor to provide copy to individual

Keep a copy for yourself to be used to enter into the record keeping system

Not Qualified

Original form to the Individual's Supervisor

Revised 6-16-04

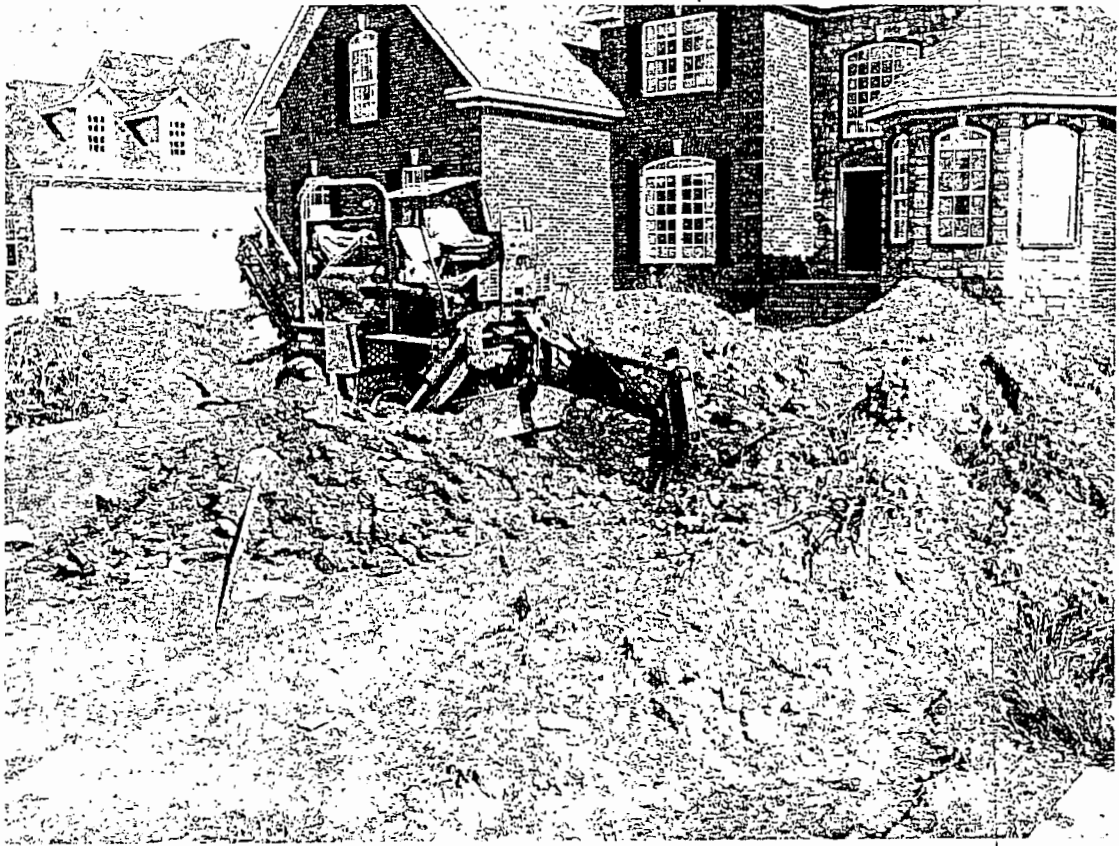


Exhibit Three

Exhibit Four

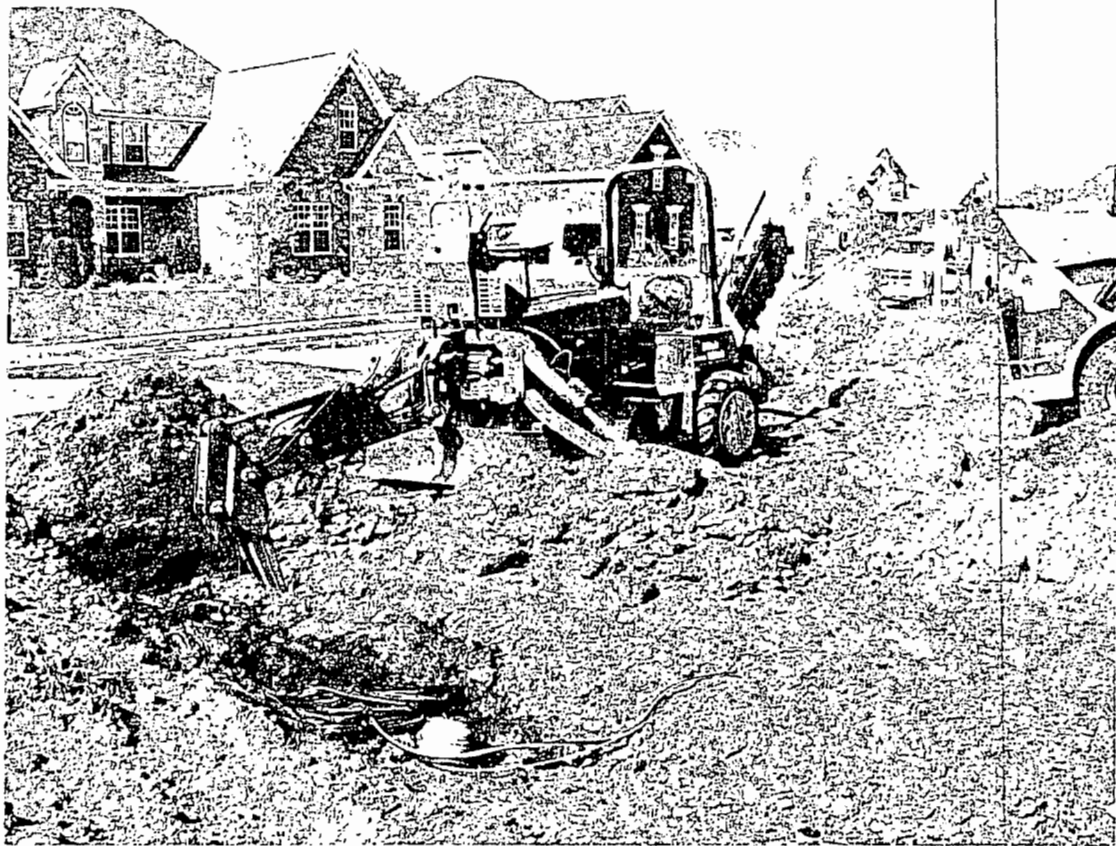


Exhibit Four

Exhibit Five



Exhibit Five

Exhibit Six



Exhibit Six

Exhibit Seven



Exhibit Seven

Exhibit Eight

Exhibit Twelve

Tom Woosley - Re: Locate Ticket

From: "Randy" <rlincoln@tnonecall.com>
To: "Tom Woosley" <Tom.Woosley@state.tn.us>
Date: 8/22/2005 2:38 PM
Subject: Re: Locate Ticket

Tom,

Yes, there was a ticket. It was entered by Atmos via GeoRemote. Ticket number is 051890145. It was updated to ticket # 052071228.
Hope this helps.

Randy

Randy Lincoln
Operations Manager
Tennessee One-Call System, Inc.

----- Original Message -----

From: Tom Woosley
To: rlincoln@tnonecall.com
Sent: Monday, August 22, 2005 2:06 PM
Subject: Locate Ticket

Randy,

Was there a ticket in place for 5410 Sherrington Drive, Murfreesboro, on August 2, 2005? This would have likely been called in by Atmos who was installing a gas service at that address.

Thanks,

Tom Woosley
Trainer/Engineer
Tennessee Regulatory Authority
Tom.Woosley@state.tn.us
1-800-342-8359 ext. 181

EXHIBIT 12

Exhibit Thirteen

Table of Contents

Section 1	Purpose and Definition
Section 2	General Responsibilities
Section 3	Commission Reporting and Telephone Numbers
Section 4	Receiving and Recording Emergency Notifications ✓
Section 5	~~Fires~~ Involving Pipeline Facilities
Section 6	Gas Detected In or Near a Building ✓
Section 7	Explosion Near or Involving Company Facilities ✓
Section 8	Interruption of Service
Section 9	Civil Disturbances
Section 10	Natural Disasters ✓
Section 11	Liaison with Governmental Agencies ✓
Section 12	Plan Dissemination

SECTION 1

EMERGENCY OPERATING PROCEDURES

ATMOS
OPERATION & MAINTENANCE
MANUAL

Purpose and Definition

The purpose of a gas emergency plan is to protect the general public and company employees from potential hazards. Each emergency creates its own set of circumstances and problems. Because of this, these procedures are written to be flexible enough to address anticipated emergencies.

For the purpose of this procedure, an emergency is any situation or notice of an incident involving natural gas or Company facilities, which require immediate response by our employees. Notices of odor, fire, explosion, leakage, damage, carbon monoxide or loss of service may require a priority response but should not be considered an emergency until it is determined that a hazard exists. Once it is determined that a hazard does exist, necessary personnel and resources will be directed to the location to take whatever actions are necessary to control and/or eliminate the emergency situation in the shortest possible time.

Company supervision shall, as soon as practical, review the employees' activities during the emergency to determine whether the emergency procedures were effectively followed.

SECTION 2

EMERGENCY OPERATING PROCEDURES

ATMOS
OPERATION & MAINTENANCE
MANUAL

General Responsibilities

Local Supervision shall make available personnel, equipment, tools and materials, as needed at the scene of an emergency. Actions will be directed toward protecting people first and then property. First responders will practice "H-E-L-P"

- H – Identify the hazard
- E – Evaluate the risk
- L – Protect life
- P – Protect property

If required, the gas system should be isolated or shutdown or the pressure reduced by utilizing valves, squeeze off tools, stoppers, and pressure regulating equipment. The primary responsibility of the responders' role is to make the area safe.

Company Handbook



Emergency Operations Procedures

Subject: Telephone and Regulatory Reporting - Tennessee

Reference: 192.615

Issue Date	Effective Date	Revision Date
09/2000	09/2000	09/2000

Regulatory Reporting - Tennessee

Accurate and timely telephone reports are required by the Pipeline Safety Act for extraordinary pipeline failures, such as,

- A) An event that involved a release of gas from a pipeline or a liquefied natural gas or gas from an LNG facility
 - 1. A death, or personal injury necessitating hospitalization, or
 - 2. Estimated property damage, including cost of lost gas of \$50,000 or more
- B) An event that results in an emergency shut down of a LNG facility
- C) An event that is significant, in the judgement of the operator, even though it didn't meet the Criteria of A or B

Local supervision will communicate to appropriate management immediately upon becoming aware of significant pipeline failure.

At the earliest possible moment following discovery of the incident, the appropriate management personnel will notify the United States Department of Transportation by telephone at 1-800-424- 8802. Within two hours of the time of notification of the incident, the appropriate management personnel will notify the designated Tennessee Regulatory Authority personnel of events requiring notification by telephone. Written reports will be filed with the Tennessee Regulatory Authority and the Department of Transportation within 30 days from the day of the incident, or as required by law.

The telephone report shall include the following information:

- 1. Names of operators and persons making report and their telephone number
- 2. Location of the incident
- 3. Time of the incident
- 4. The number of fatalities and personal injuries, if any; and
- 5. All other significant facts that are known by the operator that are relevant to the cause of the incident or extent of the damages.

Address and telephone numbers of United States Department of Transportation

Information Resources Manager
 Office of Pipeline Safety
 Research and Special Programs Administration
 U S Department of Transportation
 Room 8417
 400 Seventh Street S.W.
 Washington, D.C 20590

Telephone (800) 424-8802

Address and telephone number of the Tennessee Regulatory Authority

Tennessee Regulatory Authority
 460 James Robertson Parkway
 Nashville, Tennessee 37243-0505

Telephone (800) 342-8359, (615) 741-2844, Fax (615) 741-1228

<u>Name</u>	<u>Office</u> Extension:	<u>Home</u> (615)	<u>Cell Phone</u> (615)
Glynn Blanton	185	370-1125	476-4685
Larry Borum	182	604-6328	476-4691
Tom Woolsey	181	230-7557	476-4693
Brad Williams	186	383-6394	476-4739
Eric Cherry	133	612-1895	476-4728
Clift Phillips	187	618-0827	476-4716
Vicky Nelson	184	-	-

Washington D.C Response Center: 1-800-424-8802

Original Approved by Utility Operations Council



SECTION 4

EMERGENCY OPERATING PROCEDURES

ATMOS
OPERATION & MAINTAINANCE
MANUAL

Receiving and Recording Emergency Notifications

Information Gathering

Any employee receiving a report of, or discovering an emergency should attempt to gather and record the following information if available:

1. Calling party, phone number and address
2. Exact time reported and location of emergency
3. Nature of emergency
4. The emergency order will be dispatched immediately

Employee Response

It is the responsibility of the employee at the scene to determine the nature of the emergency, take reasonable steps to make the area safe, and to provide information and assistance to emergency forces to protect people and/or property. This factual information should immediately be relayed to the Supervisor on duty or in his absence, to the appropriate management personnel.

SECTION 5

EMERGENCY OPERATING PROCEDURES

ATMOS
OPERATION & MAINTENANCE
MANUAL

Fires Directly Involving Pipeline Facilities

When escaping gas from a main, service, or other facility has ignited, regardless of the cause, employees will implement the appropriate procedures listed below after actions have been taken to protect the public, secure the area and notify the appropriate personnel of the condition

If the source of burning gas cannot be safely shut off without jeopardizing employee safety and the gas fire does not threaten further injury or property damage, the fire may be allowed to burn until its source can be shut off

If the gas related fire threatens further injury or property damage and the supply cannot be shut off appropriately by valves, squeeze off or line stops, the fire should be extinguished by use of dry chemicals but only after the following provisions have been made

- 1 The fire department must be notified and they have equipment and personnel present
- 2 A coordinated plan will be created between the fire and/or police department and our supervisors as to how the fire shall be extinguished and how the remaining leaking gas shall be contained
- 3 Personnel extinguishing the fire or exposed to leaking gas are to wear appropriate fire protection equipment and other Personal safety equipment as necessary
- 4 Each employee thoroughly understands their role in securing the emergency and all safety related rules have been observed

SECTION 6

EMERGENCY OPERATING PROCEDURES

ATMOS
OPERATION & MAINTENANCE
MANUAL

Gas Detected In or Near a Building

In the case of gas detected or suspected inside or near a building, all Company personnel shall take such action as necessary to protect the public first and then the facilities. On-the-site judgment is required by the responsible employee to properly react to the specific situation.

Consideration should be immediately given to getting all people out of any building involved if gas is detected inside the building. In addition, gas should be turned off at the service entrance, all open flames extinguished, people advised not to connect or disconnect electrical cords or move electrical switches, and windows and doors should be immediately opened. An investigation should then be made to find the source of the leak and corrective actions taken. If a customer services the building, then they should be contacted for performing the investigation and taking corrective action after the situation is under control. Company personnel should remain on site until customer's employees arrive.

If gas is detected near a building, then all people inside should be told to extinguish all open flames, not to operate any electrical switch, to open windows and doors and then get outside immediately. A determination should immediately be made as to severity of the leak and the potential and immediate danger involved. If a customer serves the building, then they should be contacted for performing the investigation and taking corrective action after the situation is under control. Company personnel should remain on site until customer's employees arrive.

If the company's facilities are involved, then Company personnel should perform corrective actions required. Where safety permits, leak detection equipment may be utilized to locate, learn and determine the area of gas migration.

SECTION 7

EMERGENCY OPERATING PROCEDURES

ATMOS
OPERATION & MAINTENANCE
MANUAL

Explosion Occurring Near or Directly Involving a Company Facility

Immediately upon being notified of an explosion on a Company pipeline facility, the responsible person receiving the notification will inform the proper chain of command and go to the scene of the explosion to evaluate the situation. The actions required depend, upon whether the explosion actually involves a Company pipeline or were near or adjacent to pipeline facilities and the seriousness of the situation.

Should there be a serious explosion on a Company owned facility or customer, the responsible supervisor, manager, or management personnel will direct work crews to the designated location. Company emergency equipment and first aid equipment would be dispatched to the location as quickly as possible.

The responsible supervisor, manager, or management personnel will evaluate the situation and inform the proper Company and/or regulatory authorities accordingly. Where warranted, isolate the section of pipeline or squeeze the plastic main or service off. Firemen, police and the general public should be notified that, except for house meter valves, gas company personnel must operate all pipeline equipment.

In the event that fire spreads to areas adjacent to Company facilities, or people are injured and/or spectators are gathering or evacuation of people is needed, the appropriate local ambulance, hospital, fire and police officials should be immediately notified. Company employees should be assigned, if available, to assist local police and fire officials in evacuating personnel from the area by means of barricades or roping off the area or by other means as directed by the officials.

Fire, police and other officials need not be notified and assistance asked for if the explosion is of a minor nature and only involves Company facilities and presents no immediate danger to the public, adjacent properties or personnel, and the situation is under control.

SECTION 8

EMERGENCY OPERATING PROCEDURES

ATMOS
OPERATION & MAINTENANCE
MANUAL

Interruption of Service

If a service interruption or unplanned outage is reported, efforts must be made to quickly determine the extent of the outage and if possible, the reason. If necessary, isolate the affected area and begin preparations to correct the situation causing the outage.

All service riser valves will be turned off in the affected area. Meter reports in the affected area and/or system maps may be used to ensure that all riser valves are turned off in the affected area. It may be necessary to obtain law enforcement assistance to enter houses where service valves are not accessible from the outside.

After all service risers have been turned off and all necessary repairs have been made, gas will be admitted back into the system. Service restoration will begin with priority customers and continue until all available customers are back in service.

Customers left off from the outage will be reported to the area's local supervision and the call center.

SECTION 9

EMERGENCY OPERATING PROCEDURES

ATMOS OPERATION & MAINTENANCE MANUAL

Civil Disturbance Procedures

In the event of a civil disturbance within the Company's service area, the following policies and procedures will be followed

Where possible, employees of the Company will avoid travel through any area where disturbances or demonstrations are taking place

All nonessential service in areas of civil disturbances will be curtailed until authorities have established adequate order and control

Where it is necessary to dispatch a service crew into the area because of notification of a potentially hazardous situation involving our gas pipeline system or facilities, supervisory personnel shall not authorize any entrance into an area where civil disturbance is occurring unless adequate safeguards for employee safety have been taken including the assurance of police or law enforcement escort and protection

When arson, rioting, looting, sniping, etc., prevent repair crews from safely entering an area of civil disturbance to repair a leak or hazardous condition, such repairs shall be deferred until conditions are safe and police can escort a crew into the area. Consideration shall be given to shutting off gas supply to the effected area using the critical valve program if the hazard to life and property warrants

If time and conditions permit, discussion with appropriate management personnel should be made prior to shutting off gas supply to a large area. In the event the situation is critical, the responsibility to take such steps shall be the responsibility of local management

Establishing a mobile unit command post may be necessary

Liaison shall be made with police, fire, and municipal authorities to establish familiarity with this plan in case of civil disturbance

SECTION 10

EMERGENCY OPERATING PROCEDURES

ATMOS
OPERATION & MAINTENANCE
MANUAL

Natural Disaster Procedure

Emergencies due to natural disasters such as hurricanes, tornadoes, earthquakes, floods, etc , will be handled in the same manner as outlined in preceding sections of this manual

SECTION 11

EMERGENCY OPERATING PROCEDURES

ATMOS
OPERATION & MAINTENANCE
MANUAL

Liaison with Governmental Agencies

Liaison shall be established jointly between the Company the fire department, police, and other governmental agencies to insure proper communication and understanding of operating procedures during periods of emergency, civil disturbances and major gas interruptions

Fire Departments

Liaison should be maintained with all fire departments serving an area in which the Company has gas facilities. Fire departments should be instructed not to operate any main line valves and regulator stations. In addition, they should be instructed not to turn off blowing relief valves on regulators.

In contacts with fire departments, emphasis shall be placed on the necessity to notify Company personnel regarding all fires where gas or gas facilities are involved, all gas leaks or suspected gas leaks or combustible vapors of an unknown origin found in sewers or buildings.

Police Departments

Police departments shall be visited periodically to familiarize these agencies with the Company's facilities and emergency operating procedures. These agencies should also be informed as to what steps to take when relief valves vent, vandalism occurs, or accidents happen affecting gas facilities.

Other Governmental Agencies

Sufficient rapport shall be established with any other agencies as deemed necessary to insure as smooth an operation as possible during emergencies, civil disturbances and gas interruptions.

SECTION 12

EMERGENCY OPERATING PROCEDURES

ATMOS
OPERATION & MAINTENANCE
MANUAL

Plan Dissemination

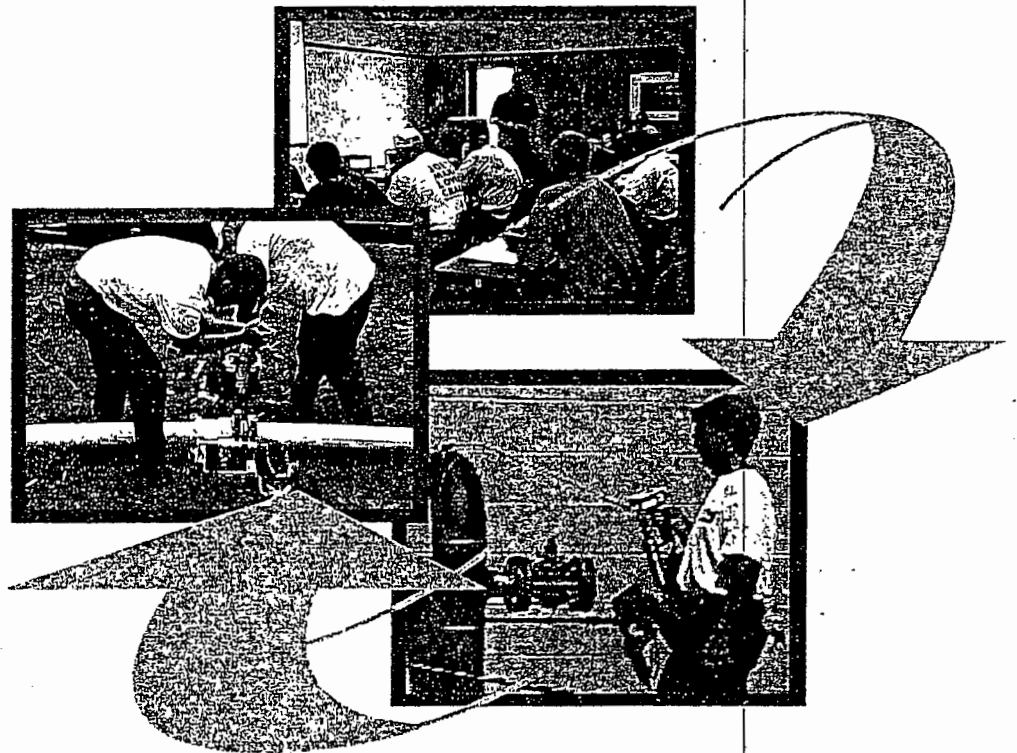
The latest edition of the emergency procedure established under section (a) of 192.615 will be provided to each supervisor who may be responsible for emergency action.

Local supervision shall be responsible for training the appropriate operating personnel to assure that they are knowledgeable of the emergency procedures and verify that the training is effective.

Exhibit Fourteen



Student Manual



GDS 1.1 (OQ M-8) Preventing Accidental Ignition

INDUSTRIAL TRAINING SERVICES, INC
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Phone (270) 753-2150
Fax (270) 753-9807



Preventing Accidental Ignition Caused by Electric Arcing

Sparks range in temperature from 1500°F in an electrical switch to 9,000°F in an arc welder. Sparks may be generated by

- Portable electrically powered tools and equipment
- Internal combustion engines
- Breaking electrical continuity
- Static electricity on plastic pipe

- (1) **Portable Electrically Powered Tools and Equipment.** Flashlights, portable floodlights and extension cords and any other electrically powered tool or equipment should be of a type approved for use in hazardous atmospheres
- (2) **Internal Combustion Engines.** Internal combustion engines that power trucks, cars, compressors, pumps, generators and other equipment should not be operated in suspected or known hazardous atmospheres
- (3) **Breaking Electrical Continuity.** Electricity on gas facilities can produce an electric shock to a worker. An electric arc can be produced when a steel main is cut or separated. This potential ignition source can be present because

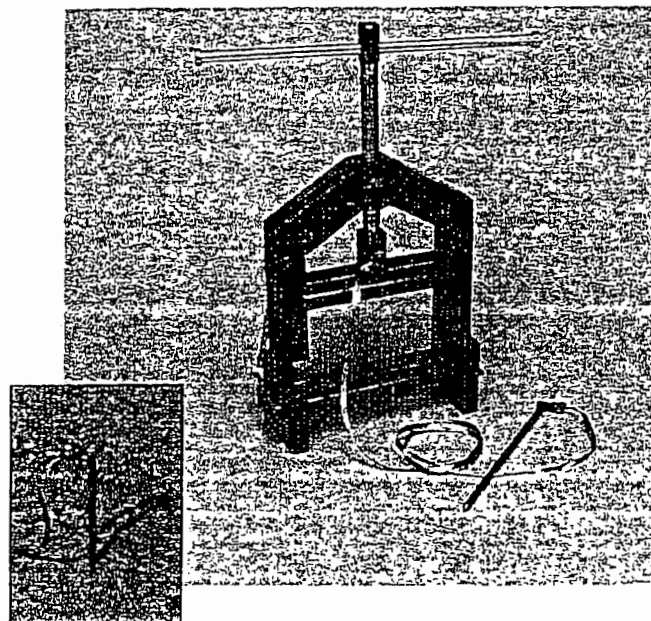
- Gas piping has been used for a ground for an electric service.
- Alternating current may be induced on gas line running parallel to or near high voltage electric transmission lines.
- Stray direct currents may be carried by pipelines in areas where direct current systems are used
- Direct current may be present on pipelines as a result of cathodic protection devices such as anodes or rectifiers

To prevent arcing and the possible ignition of gas when a steel main is to be separated, install temporary bonding clamps across the area where the cut is to be made. This will allow a path for electrical current that could be on the main. This will prevent having an electric arc

- (4) **Static Electricity in Plastic Pipe.** Static electricity in its simplest form is not dangerous, it causes:

- Mild shocks
- Unruly hair
- Clinging clothes

However, to those involved with replacing, purging, or extending existing plastic, static electricity is recognized as a possible ignition source and thus a potential hazard



Courtesy Allied Corrosion Industries, Inc

Figure 1 Four-Inch 1PS Squeeze Tool with Static Electric Grounding Device

Controlling Static Electricity on Plastic Pipe

When confronted with a gas leak from damaged plastic piping, stopping the flow of gas by squeeze-off in separate bell holes is the initial consideration. As illustrated in Figure 2, these bell holes should be adjacent to, but far enough away from the gaseous atmosphere, to prevent ignition (should a static discharge occur). Be sure to properly ground squeeze-off tools while working with them. A method used to control static electricity on plastic pipe in a gaseous atmosphere is to wet the pipe with an anti-static solution. This wetting process should be done before entering the bell hole.

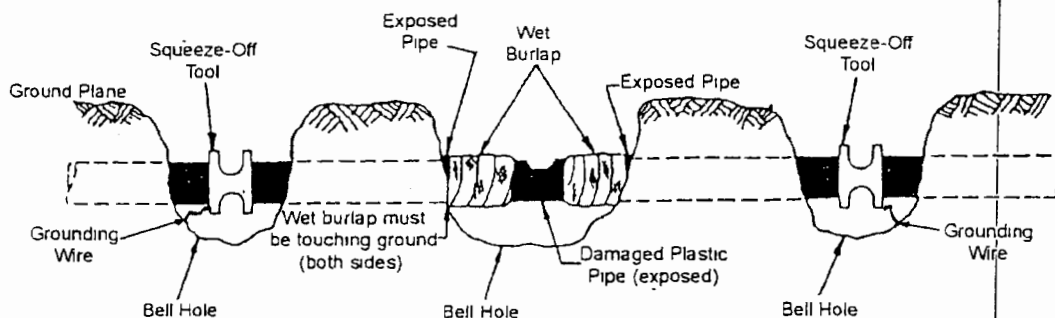


Figure 2. Controlling Static Electricity When a Squeeze-Off Tool is Used

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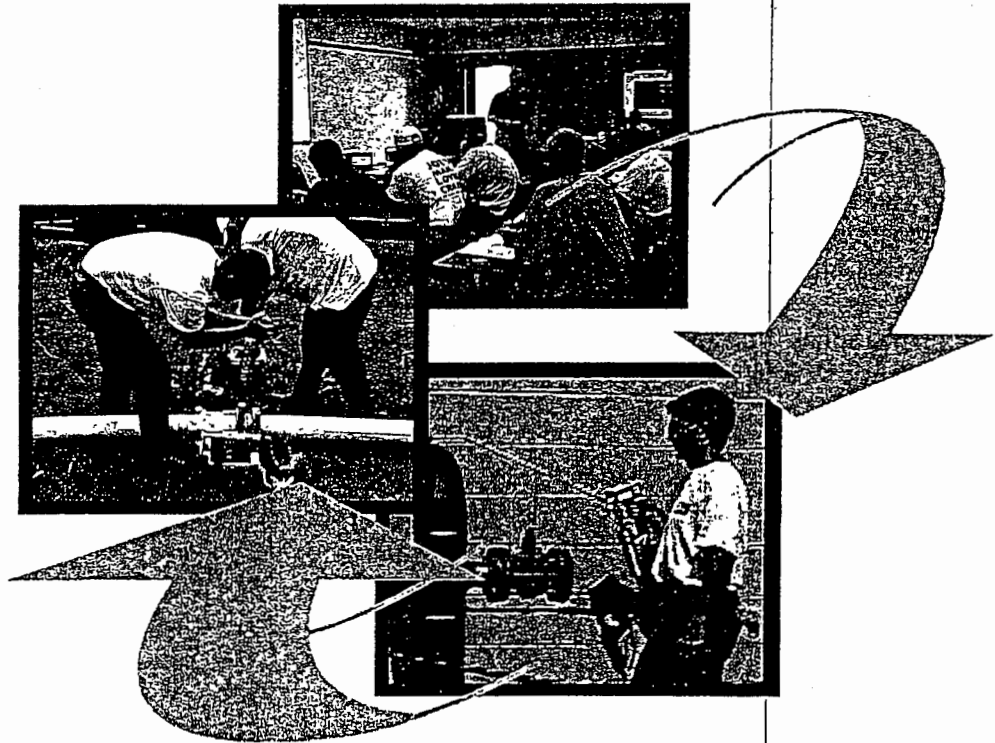
GDS 1.1 - OQ M-8

Atmos

Exhibit Fifteen



Student Module



GDS 7.9 (OQ M-14) Identifying Excavation Damage Prevention Practices

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Excavation Practices Used to Avoid Damage

Practices that reduce the probability of damage during an excavation activity includes the following:

- Plan the excavation to avoid damage to underground facilities in and near the construction area
- Maintain a safe clearance between the underground facilities and the cutting edge of any mechanized equipment, taking into account the known limit of control of the cutting edge, to avoid damage to facilities
- Provide support for underground facilities in and near the construction area during excavation and backfilling operations to protect the facility
- Dig test pits to determine the actual location of gas facilities if these facilities or utilities are to be exposed or crossed
- Dig by hand inside the tolerance zone
- Beware of the possibility of abandoned facilities. Find, expose and protect all facilities within the tolerance zone
- Avoid the use of picks and mattocks.
- When hand digging in hard compacted soils, potholes to the side of the locate marks and collapse the soil into the pothole while digging toward the marks
- Usually an excavation within the location tolerance zone must be performed with hand tools until the marked facility is exposed
- Beware of the possibility of unmarked laterals running from buried cables to pedestal, cross-boxes and poles.
- The depth of facilities is not guaranteed. The excavation is responsible for finding and avoiding all facilities down to the depth he/she is working.
- If you have any doubts, request that the site be remarked.
- The hand digging zone is 18" each side of the width of the facility, as illustrated in Figure 2.

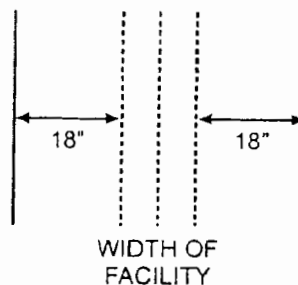
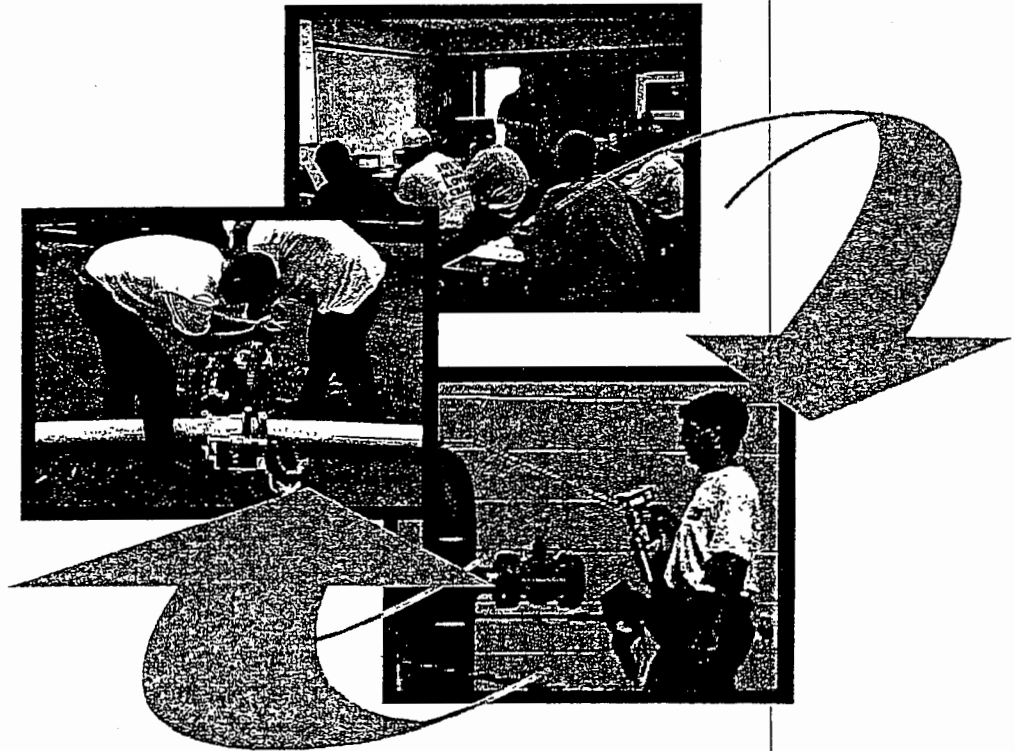


Figure 2 Hand Digging Zone

Exhibit Sixteen



Student Module



GDS 2.8
(OQ M-13)

Responding to a Natural Gas Emergency

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- (6) **Overpressure in System.** As soon as it is learned that an overpressure condition exists in the system, proper steps must be taken to permanently correct the condition that caused the malfunction.

Pressure is limited to 90 PSIG for High Density polyethylene pipe or 60 PSIG for Medium polyethylene pipe

System overpressure must be considered as a failure and investigated immediately according to company policy

- (7) **Underpressure in System.** As soon as it is learned that an underpressure condition has occurred in the system, it is necessary to determine the cause of the failure. Possible causes are.

- Malfunction of the pressure regulating equipment at the supply
- System demand exceeding capacity of the regulator station
- Unauthorized operation of a main valve at the regulator station
- Shortage of supply

The effects of the low pressure upon customers farthest away from the supply must be checked to determine if any outage have occurred. If outages occur, those customers should be shut off at the meter and reinstated when the problem is corrected.

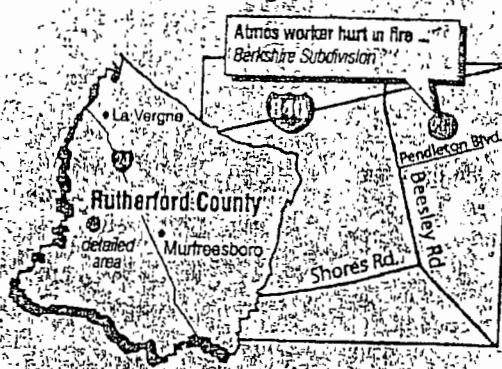
System underpressure must be considered as a failure and investigated in accordance to the Operation and Maintenance Plan

- (8) **Fire or Explosion Directly Involving Gas.** Immediately upon receipt of notice of a fire or explosion directly involving gas, the following actions shall be taken

- Maps and records for the location involved shall be accessed and locations of mains and service lines
- Qualified personnel equipped with tools required to shut off a service line or main shall be dispatched to the scene
- Upon arrival at the scene, contact should be made with the Fire Chief or other lead emergency response person. Necessary actions shall be planned and carried out accordingly

In cooperation with Fire Officials, an investigation should be made to determine with certainty whether gas was involved. Leak survey, pressure testing of service line and house piping, and performance testing of the service regulator may be appropriate

Exhibit Seventeen



Atmos worker suffers burns in work blaze

■ Digging accident causes gas line to rupture, explode

By LISA MARCHESONI
marchesoni@dnj.com

An Atmos Energy employee is expected to fully recover after suffering burns to his forearms and hands when a gas line ignited Tuesday during a work accident on Sherrington Road, a company spokeswoman said.

The identity of the Murfreesboro man, his age and severity of his injuries were not released because of federal privacy laws, said Denise Manning, Atmos public affairs manager.

He was flown by LifeFlight helicopter to Vanderbilt University Medical Center in Nashville where family members and fellow employees gathered.

Center spokesman Jerry Jones said the man was admitted to the burn unit where he was listed in critical condition.

Manning said the longtime employee was resting Tuesday afternoon.

"We're thankful that everything's manageable, and the employee is expected to fully recover," Manning said.

Murfreesboro Fire Capt. Thomas Adams said the man and a co-worker were installing a new service line at Berkshire subdivision off Beesley Road and state Route 96 West (Franklin Road) south of state Route 340.

(See ATMOS, page A4)

ATMOS

(continued from page 1)

when they dug through a gas line causing it to ignite.

"He was burned badly," Thomas said.

Firefighters responded about 8:30 a.m. to the scene with Emergency Medical Services paramedics behind them.

Fire Chief Tim Swann said the men were using a backhoe and a ditch witch to work on the line when it erupted, burned the employee and caught the ditch witch on fire.

Adams confirmed that the gas line was connected.

When the gas was burning, flames were shooting 25 to 30 feet

in the air," Adams said.

When firefighters arrived on the scene, Swann said, they waited about 10 minutes for Atmos officials to shut off the gas before they could extinguish the fire.

Once they cut the gas off, it was out within a couple of minutes, Swann said.

If firefighters hadn't waited, Adams explained, the gas could have exploded and made the fire spread. Firefighters sprayed the ground with water to keep the fire from spreading to a nearby house under construction.

Manning said eight or nine Atmos customers were affected when the gas was turned off for several hours Tuesday.

"We have finished repairing that site," Manning said. "The scene is safe."

Exhibit Eighteen

CIVIL PENALTY SCHEDULE

In determining the civil penalty for each violation, the following state and federal statutes were considered, Tennessee Code Annotated, Section 65-28-108

“(a) Any person who violates any provision of §§ 65-28-104 -- 65-28-111, or of any regulation issued under such sections, is subject to a civil penalty not to exceed ten thousand dollars (\$10,000) for each such violation for each day that such violation persists, except that the maximum civil penalty shall not exceed five hundred thousand dollars (\$500,000) for any continuing series of violations

(b) Any civil penalty may be compromised by the authority. In determining the amount of such penalty, or the amount agreed upon in compromise, the appropriateness of such penalty to the size of the business of the person charged, the gravity of the violation, and the good faith of the person charged in attempting to achieve compliance, after notification of a violation, shall be considered. The amount of such penalty, when finally determined, or the amount agreed upon in compromise, shall be paid within thirty (30) days after the determination to the authority, to be used for the purposes of §§ 65-28-104 -- 65-28-111, and, if not paid within such time, may be recovered in a civil action brought by the authority in the chancery court of any county in which a violation exists [Acts 1970, ch. 558, § 6, T.C.A., § 65-2809, Acts 1991, ch. 439, § 2, 1995, ch. 305, § 36.]”

The Pipeline Safety Act (Public Law 90-481, 49 U.S.C. § 1671 et seq.) addresses the federal statute pertaining to violations of the Minimum Federal Safety Standards, Section 60122 states:

“(a) GENERAL PENALTIES

(1) A person who the Secretary of Transportation decides, after written notice and an opportunity for a hearing, has violated Section 60114(c) or 60118(a) of this title or a regulation prescribed or order issued under this chapter is liable to the United States Government for a civil penalty of not more than \$25,000 for each violation. A separate violation occurs for each day the violation continues. The maximum civil penalty under this paragraph for a related series of violations is \$500,000.

(2) A person violating a standard or order under Section 60103 or 60111 of this title is liable to the Government for a civil penalty of not more than \$50,000 for each violation. A penalty under this paragraph may be imposed in addition to penalties imposed under paragraph (1) of this subsection.

(b) PENALTY CONSIDERATIONS.

In determining the amount of a civil penalty under this section, the Secretary shall consider –

- (1) the nature, circumstances, and gravity of the violation;
- (2) with respect to the violator, the degree of culpability, any history of prior violations, the ability to pay, and any effect on ability to continue doing business,
- (3) good faith in attempting to comply; and,
- (4) other matters that justice requires

(c) COLLECTION AND COMPROMISE

- (1) The Secretary may request the Attorney General to bring a civil action in an appropriate district court of the United States to collect a civil penalty imposed under this section.
- (2) The Secretary may compromise the amount of a civil penalty imposed under this section before referral to the Attorney General.

(d) SETOFF

The Government may deduct the amount of a civil penalty imposed or compromised under this section from amounts it owes the person liable for the penalty

(e) DEPOSIT IN TREASURY

Amounts collected under this section shall be deposited in the Treasury as miscellaneous receipts

(f) PROHIBITION ON MULTIPLE PENALTIES FOR SAME ACT.

Separate penalties for violating a regulation prescribed under this chapter and for violating an order under Section 60112 or 60118(b) of this title may not be imposed under this chapter if both violations are based on the same act.”

In assessing the amount for the violation, we took into consideration the nature of the violation, the notices you have received from the Federal Office of Pipeline Safety and Tennessee Regulatory Authority in an Alert Notice and informational mailings concerning compliance with pipeline safety rules and regulations. An amount of \$10,000 per violation was used in determining the civil penalty in accordance with TCA § 65-28-104. The violation amount was multiplied by the number of days the violation was outstanding times the size of the natural gas distribution system, and divided by the public safety factor. See the formula, public safety factor, length of time violation was outstanding and total amount for each violation listed below. In consideration of our state statute, the total civil penalty assessed is \$13,000

Formula

$$\text{Civil Penalty Amount} = \frac{\text{Violation} \times \text{Number of days} \times \text{Size of natural gas distribution system}}{\text{Public safety factor number}}$$

Public Safety Factor

Factor Number

Type of Violation

1.00

Priority 1 - Any violation which, if not immediately corrected, could present a hazardous condition to life, property or both

2.0

Priority 2 - Any violation which needs prompt attention because the failure to correct could result in loss of service and / or reliability to the customer

3.0

Priority 3 - Any violation which needs attention because the operator has failed to complete or schedule maintenance activities.

Factor Number

Size of Natural Gas Distribution System

.35

1 to 2,000 gas meters

.50

2,001 to 10,000 gas meters

.65

10,001 to 50,000 gas meters

1.0

50,000 or more

Atmos Energy: Murfreesboro

Natural Gas Pipeline Incident

August 2, 2005

<u>Violation</u>	<u>Formula</u>	<u>Maximum Civil Penalty</u>
192.605(a)	$\frac{\$10,000 \times 1 \times .65}{2.0}$	= \$ 3,250
192.615(a)	$\frac{\$10,000 \times 1 \times .65}{2.0}$	= \$ 3,250
192.751(a)	$\frac{\$10,000 \times 1 \times .65}{1.0}$	= \$ 6,500
Potential Maximum Civil Penalty		= <u>\$13,000</u>

BEFORE THE TENNESSEE REGULATORY AUTHORITY

NASHVILLE, TENNESSEE

August 2, 2006

IN RE:	)	
	)	
ATMOS ENERGY CORPORATION-	)	DOCKET NO.
MURFREESBORO INCIDENT 8/2/05, FORMAL	)	05-00323
NOTICE OF VIOLATIONS -REPORT OF	)	
NATURAL GAS SAFETY INSPECTION #05-267	)	

ORDER APPROVING PROPOSED CIVIL PENALTY AND
ACCEPTING RESPONSE OFFERING LONG TERM CORRECTIVE ACTIONS

This matter came before Chairman Ron Jones, Director Pat Miller and Director Sara Kyle of the Tennessee Regulatory Authority (the "Authority" or "TRA"), the voting panel assigned to this docket, at a regularly scheduled Authority Conference held on March 20, 2006 for consideration of the Formal Notice of Violation ("FNOV") issued by the TRA's Gas Pipeline Safety Division and the response by Atmos Energy Corporation ("Atmos") proposing a plan of long-term corrective action and accepting the penalty amount.

BACKGROUND

On August 2, 2005, a release of natural gas occurred on a two-inch polyethylene distribution main operated by Atmos and located at 5410 Sherrington Drive, Murfreesboro, Tennessee. The natural gas was ignited, resulting in injury to one Atmos employee who was transported to Vanderbilt University Medical Center where he was admitted for burns received in the incident.

Under authority set forth in Tenn. Code Ann. § 65-28-106 and 49 U.S.C. § 60105(a), the Gas Pipeline Safety Division ("Investigative Staff") conducted an investigation of this

incident. The purpose of this investigation was to determine cause and whether there were violations of federal safety standards as adopted by the State of Tennessee in Tenn. Code Ann. § 65-28-105 and applied to gas utilities through TRA Rule 1220-4-5-.48.

The investigation of this incident is detailed in Gas Safety Inspection Report #05-267 filed by Investigative Staff in this docket on December 1, 2005. In this Report, the Investigative Staff concludes that the incident resulted from the failure of Atmos employees to follow established written procedures for avoiding damage to underground natural gas lines when excavating. Specifically, the operator of mechanized excavation equipment failed to maintain a safe distance from the gas line to avoid damage to facilities. The damage to the gas line by the cutting edge of the backhoe bucket also evidences that hand digging was not performed within the tolerance zone that is prescribed in Atmos' written procedures for performing this task.

After the gas line was damaged and with gas being released, additional digging was performed with the backhoe to expose the damaged main for repair. This action caused an ignition source to be in close proximity to a hazardous atmosphere, action strictly forbidden by 49 C.F.R. § 192.751(a) of the Minimum Federal Safety Standards ("MFSS") which requires that all ignition sources be removed from the area when the presence of gas "constitutes a hazard of fire or explosion."¹

The Report by Investigative Staff states that natural gas operators are required by Section 192.605(a) to develop and follow "a manual of written procedures for conducting operations and maintenance activities."² These procedures must be in sufficient detail to avoid any confusion or doubt as to the manner in which the individual should handle the task or emergency situation. While the Atmos manuals may address some or all areas required by

¹ 49 C.F.R. § 192.751(a)

² 49 C.F.R. § 192.605(a)

the MFSS, they did not mirror the procedures that employees are taught for use in performing their assigned tasks. These same procedures are used to determine the employee's qualification for such tasks. Because those procedures are required to be but, in fact, were not located in the Operations and Maintenance, the manual was determined by the Investigative Staff to be inadequate.

Also, according to Investigative Staff, Atmos failed to include adequate written procedures in its Emergency Operating Procedures that address the appropriate response to uncontrolled escaping gas. This fact demonstrates that Atmos failed to sufficiently adhere to 49 C.F.R. § 192.615(a) which states, "Each operator shall establish written procedures to minimize the hazard resulting from a gas pipeline emergency."

On November 28, 2005, the Investigative Staff issued a FNOV to Atmos for failing to comply with 49 C.F.R. § 192.605(a), § 192.615(a), and § 192.751(a).³ In the FNOV, under provisions of Tenn. Code Ann. § 65-28-108, the Investigative Staff also assessed a civil penalty in the amount of \$13,000. Atmos was required to respond to the FNOV in one of three ways. Atmos could either: (1) submit a written statement of corrective measures that have achieved compliance, (2) submit a written plan of action outlining the corrective measures that will be taken and when compliance is anticipated, or (3) request an informal conference with the Gas Pipeline Safety Division Chief.⁴

The civil penalty amount of \$13,000 was determined by applying a formula which has been utilized in the past by the Gas Pipeline Safety Division. The amount of ten thousand dollars (\$10,000) per day per violation is used in the formula. This is the maximum daily

³ Section 192.605(a) details required provisions and procedures for Operations and Maintenance manuals. Section 192.615(a) details required provisions and procedures for Emergency Response plans. Section 192.751(a) requires the removal of possible sources of ignition whenever a hazardous amount of gas is present.

⁴ See TRA Rule 1220-4-5-.47(6).

amount allowed by Tenn. Code Ann. § 65-28-108.⁵ The penalty amount is determined by applying other factors in the calculation. These factors include the public safety, the size of the natural gas system, and amount of time the violation existed. Each of these factors are given a certain weight from 1.0 to 3.0 depending upon the factual circumstances. Because three violations were cited, the penalty for each violation was assessed separately as follows:

	Civil Penalty Amount		$\frac{\$10,000 \times \text{No. of Days} \times \text{System Size Factor}}{\text{Public Safety Factor}}$
§192.605(a):	\$3,250	=	$\frac{\$10,000 \times 1.0 \times 0.65}{2.0}$
§192.615(a):	\$3,250	=	$\frac{\$10,000 \times 1.0 \times 0.65}{2.0}$
§192.751(a):	\$6,500	=	$\frac{\$10,000 \times 1.0 \times 0.65}{1.0}$
	<u>\$13,000</u>	=	Potential Maximum Civil Penalty

In the above formula, the violation of Section 192.751(a) was assigned the highest priority for public safety in that is needed to be corrected immediately to protect the public. For this reason, this violation was assigned a 1.0 as the public safety factor. Both Sections 192.605(a) and 192.615(a) violations were assigned a public safety factor of 2.0 because the violation required prompt not immediate attention and the failure to correct could result in loss of service and/or reliability to the customer. The amount of time in all three instances in this case was one day. The gas system size factor was assigned 0.65 to correlate to gas systems with 10,001 to 50,000 gas meters.

Atmos responded to the FNOV in writing on December 8, 2005, requesting an informal conference pursuant to TRA Rule 1220-4-5-.47(6)(a)(3). Informal conferences took place at the offices of the TRA in Nashville, Tennessee on January 10 and February 9, 2006. In an effort to resolve this matter, Atmos submitted in writing, on February 28, 2006, a proposed Action Plan designed to (1) monitor and evaluate the effectiveness of Atmos'

⁵ Tenn. Code Ann. § 65-28-108 provides that the overall maximum penalty is \$500,000.

ongoing safety and operation and maintenance policies and procedures, (2) improve upon such policies and procedures where applicable and (3) reassert the importance of personal responsibility in executing assigned job duties per established procedures. Atmos agreed with the findings and conclusions set forth in the Gas Pipeline Safety Division's FNOV. In addition, Atmos agreed to pay the full amount of \$13,000 assessed penalty upon approval of the agreement by the Authority.

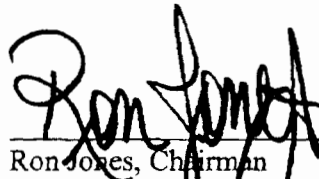
MARCH 20, 2006 AUTHORITY CONFERENCE

At a regularly scheduled Authority Conference held on March 20, 2006 the panel reviewed and discussed the FNOV and proposed plan of action. After careful review, the panel determined the Gas Pipeline Safety Division properly conducted its incident investigation under authority established in both federal and state statutes and regulations. The Gas Pipeline Safety Division assessed a fair and reasonable civil penalty for the aforesaid violations based on the evidence discovered in the course of the investigation. The panel also found that Atmos has responded with immediate corrective action and proposed long term corrective action and acknowledged that Atmos is in agreement with the Gas Pipeline Safety Division findings and has agreed to pay the full amount of civil penalty.

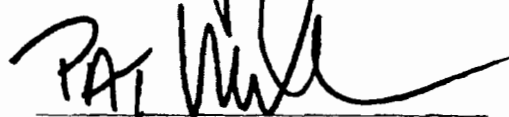
The panel voted unanimously to approve the Gas Pipeline Safety Division's FNOV and proposal for civil penalties and to accept Atmos' response offering a long-term corrective action plan and payment of the penalty amount. Under provisions of the Gas Pipeline Safety Division's certification with the Federal Department of Transportation and Tenn. Code Ann. §65-28-108, assessed penalties are dedicated for use in Tennessee's Gas Pipeline Safety program. Therefore, payment of the \$13,000 penalty would be made directly to the TRA. The panel voted unanimously that Atmos would submit the full payment of \$13,000 to the TRA by April 19, 2006.

IT IS THEREFORE ORDERED THAT:

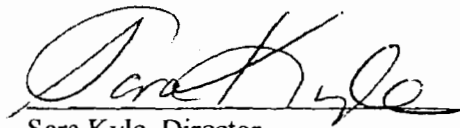
1. The Formal Notice of Violation is approved and, as filed in this docket, is incorporated into this Order as if fully rewritten herein.
2. The Response to Notice of Violation is accepted and, as filed in this docket, is incorporated into this Order as if fully rewritten.
3. Atmos Energy Corporation is ordered to make full payment of Thirteen Thousand Dollars (\$13,000) in civil penalty to the TRA by April 19, 2006.⁶



Ron Jones, Chairman



Pat Miller, Director



Sara Kyle, Director

⁶ Atmos made payment of the civil penalty in the amount of \$13,000 to the Authority on April 17, 2006.

TENNESSEE REGULATORY AUTHORITY

Sara Kyle, Chairman
Eddie Roberson, Director
Pat Miller, Director
Ron Jones, Director



460 James Robertson Parkway
Nashville, Tennessee 37243-0505

June 13, 2007

MEMORANDUM

To: Docket File

From: Carsie D. Mundy *CSM*
Chief-Consumer Services Division

Subject: *Alleged Violations by Atmos Energy Corporation of Stipulations Adopted in*
Docket No. 05-00281
Docket No. 07-00152

Attached for the file, is the signed settlement agreement in this Docket.

Attachments: 1

BEFORE THE TENNESSEE REGULATORY AUTHORITY

NASHVILLE, TENNESSEE

IN RE:

**ALLEGED VIOLATIONS BY ATMOS
ENERGY CORPORATION OF
STIPULATIONS ADOPTED IN DOCKET
NO. 05-00281**

DOCKET NO. 07-00152

SETTLEMENT AGREEMENT

This Settlement Agreement has been entered into between the Consumer Services Division ("CSD") of the Tennessee Regulatory Authority ("Authority" or "TRA") and Atmos Energy Corporation ("Atmos") and is subject to the approval of the Directors of the TRA.

This Settlement Agreement pertains to issues relating to Atmos's actions in terminating service to thirty-three (33) customers between the period of November 1, 2005 through March 31, 2006. As discussed briefly below, specific procedures had been adopted by the Authority that natural gas companies were required to follow prior to terminating service for customers during the relevant time period.

At a regularly scheduled Authority Conference on September 26, 2005, representatives of Atmos, Chattanooga Gas Company and Nashville Gas Company (collectively, the "Companies") appeared at the request of the Authority to address each utility's efforts to educate consumers concerning increasing gas prices and the affordability of rates.¹ On October 14, 2005, the Companies filed a petition which set forth stipulations regarding the equal payment plans of the

¹ See Transcript of Authority Conference, pp. 35-86 (September 26, 2005).

Companies to be effective November 1, 2005 through March 31, 2006. The stipulations would put into place temporary procedures to modify the prerequisites for entering into such equal payment plans and to prevent unnecessary service disconnection due to non-payment of bills for customers who, except for the extremely high cost of natural gas predicted for the upcoming winter, would be able to pay their bills. In pertinent part, the stipulations provided that for qualified customers their billing methodology would be automatically adjusted to an equal payment plan methodology prior to terminating service for non-payment. The petition was granted at a regularly scheduled Authority Conference held on November 7, 2005.

Based on Atmos's reports filed with the TRA regarding customer service terminations, a series of data requests and responses between the TRA Staff and Atmos ensued. In that information exchange, Atmos and the TRA staff discovered that thirty-three (33) customers had service erroneously disconnected before being placed on budget billing as required by the November 7, 2005 stipulations.

Tenn. Code Ann. § 65-4-104 (2004) gives the Authority general supervisory and regulatory power, jurisdiction and control over all public utilities, their property, property rights, facilities and franchises. The Authority lawfully exercised said power when it granted the Companies' petition in Docket No. 05-00281 which set forth stipulations regarding the equal payment plans and cut-off procedures of the Companies to be effective November 1, 2005 through March 31, 2006. Although Atmos contends that it did not intentionally fail to comply with the terms of the Authority's order and that the alleged failure was inadvertent, Atmos does not dispute that it was required to comply with said order of the Authority.

Tenn. Code Ann. § 65-4-120 provides for a penalty of fifty dollars (\$50) per day to be levied at the discretion of the Authority for each day a public utility fails to comply

with the Authority's lawful order. Atmos's violation of the stipulations set out in the Authority's November 7, 2005 order is reasonably calculated as the number of days customers were inappropriately without service (measured either from cut-off to re-connection or cut-off to the end of the period covered by the stipulations whichever is shorter). Based on that formula, Atmos was in violation for four hundred eighty two (482) days and therefore the calculable penalty for the alleged violation is twenty-four thousand one hundred dollars (\$24,100).

Atmos has suggested in the alternative, however, that it pay thirty thousand dollars (\$30,000) into its Home Energy Conservation Pilot Project as appropriate restitution for its error. Further, Atmos has made every good faith effort to make whole the thirty-three (33) customers harmed by its actions, including refunding any and all re-connection or other such fees or penalties that may have been levied against said customers who had service re-connected. As to the affected customers who did not have service re-connected, the parties agree that no further efforts on Atmos's part are required.

Therefore, the CSD and Atmos agree to settle this matter upon the following acknowledgements and terms, subject to approval by the Directors of the TRA:

1. Atmos Energy Corporation terminated the service of thirty-three (33) customers between the period of November 1, 2005 through March 31, 2006 in contravention of the stipulations approved on November 7, 2005 by the Authority in Docket No. 05-00281. However, the parties agree that any such violation by Atmos was unintentional.
2. Since receiving notice of the issues that are the subject of this Agreement, Atmos Energy Corporation has exhibited good faith in its efforts to make customers whole who were affected by the erroneous termination of service, including crediting any re-connection fee to any customers who may have been charged with such a fee when service was re-connected.

3. Atmos Energy Corporation agrees to add an additional amount of thirty thousand dollars (\$30,000) into its Home Energy Conservation Pilot Project in settlement of these issues within thirty (30) days of the Authority's approval of this Settlement Agreement and agrees to file notice with the TRA when such payment has been made. Upon payment of the amount of thirty thousand dollars (\$30,000) in compliance with the terms and conditions of this Settlement Agreement, Atmos Energy Corporation is excused from further proceedings in this matter.
4. If any clause, provision or section of this Settlement Agreement shall, for any reason, be held illegal, invalid or unenforceable, such illegality, invalidity or unenforceability shall not affect any other clause provision or section of this Settlement Agreement and this Settlement Agreement shall be construed and enforced as if such illegal, invalid or unenforceable clause, section or other provision had not been contained herein.
5. This Settlement Agreement represents the entire agreement between the parties, and there are no representations, agreements, arrangements or understandings, oral or written, between the parties relating to the subject matter of this Settlement Agreement which are not fully expressed herein or attached hereto.
6. Atmos Energy Corporation agrees that a company representative will attend the Authority Conference during which the Directors consider this Settlement Agreement.
7. In the event that Atmos Energy Corporation fails to comply with the terms and conditions of this agreement, the Authority reserves the right to re-open this docket. Atmos Energy Corporation shall pay any and all costs incurred in enforcing the Settlement Agreement.

C. D. Mundy
Carsie D. Mundy
Chief, Consumer Services Division
Tennessee Regulatory Authority

6-13-07
Date

William T. Ramsey
Signature

William T. Ramsey
Print Name

Attorney for Atmos
Print Title

6/13/07
Date

Profitability Model

Project Summary

Project Name:	CAPD DR - 105, Main Extensions
Company and State:	Tennessee
Prepared By:	0
Date:	7/14/2007

Version 5.2.0

Total Capital Costs	\$11,634	
Total AIC	\$0	
Total Capital Outlay	\$11,634	
Total Marketing Programs	\$0	
Total Project Cost	\$11,634	
Total Refundable Advance	\$0	
Economic Life of Project	30	Years
Depreciated	30 Years (3.3%)	

Economic Indicators		
Internal Rate of Return	12.77	%
Net Present Value	\$3,630	
Payback:	12	Years
	4	Months
Average ROE for First 5 Years:	11.3	%

Atmos Economic Analysis

Corporate Variables

Atmos Overhead:	11.73	%	Variables For: Tennessee	
Percent Debt:	~~50~~ 53.03	%		
Percent Equity:	~~50~~ 43.38	%	Company Overhead:	
ATWACC:	84 7.96	%		
Discount Rate	ST! 3.59	%	Stores Overhead:	
(using ATWACC):	8.4	%		
Cost of Debt:	5.8	%	Blended Income Tax Rate:	
IRR Guess:	11	%		
Interest Earnings Rate:	1.2	%	Benefits Rate:	
			Ad Valorem Tax Rate:	

Main Extension Agreement:

Residential:

Year	Amount to be Refunded
1	\$0.00
2	\$0.00
3	\$0.00
4	\$0.00
5	\$0.00
6	\$0.00
7	\$0.00
8	\$0.00
9	\$0.00
10	\$0.00

Commercial & Industrial:

Year	Amount to be Refunded
1	\$0.00
2	\$0.00
3	\$0.00
4	\$0.00
5	\$0.00
6	\$0.00
7	\$0.00
8	\$0.00
9	\$0.00
10	\$0.00

Non-Refundable Contributions:	\$0.00
Committed Refundable Advance:	\$0.00

Reflected Results		
Internal Rate of Return (%)	12.8	%
Net Present Value	\$3,630.16	
Payback Period (Years)	12	
(Months)	4	
Average ROE for First 5 Years:	11.3	%

Use the spaces below to input the marketing costs that will be associated with this project.

Year	Cost \$
1	\$0.00
2	\$0.00
3	\$0.00
4	\$0.00
5	\$0.00
6	\$0.00
7	\$0.00
8	\$0.00
9	\$0.00
10	\$0.00

Determine the X needed to to have an X of:

0

%

Calculate

margin needed:

per mcf

Determine the X needed to to have a X of:

0

years

Calculate

margin needed:

per mcf

Determine the X needed to to have an X of:

0

%

Calculate

contribution needed:

per mcf

This is the Profitability Model for Atmos Energy Corp. This worksheet serves as a tool when evaluating the monetary effect a project might have on the corporation.

To begin using the model, click on the "Next" button. It will take you to the "Project Description" screen.

All inputs are shown in the shaded yellow boxes.

Use the "Menu", "Next", and "Back" buttons to navigate within the model.

The "Next" button will take you through all of the input screens.

Comment instructions are included throughout the worksheet- simply place your cursor over the red triangles.

Use the "Reset Worksheet" button on the menu screen to reset all inputs (except rates and load profiles) to zero.

The output is shown on two pages titled "Summary" and "Summary Detail".

Remember **-all overheads are automatically calculated into the capital costs entered into the spreadsheet.**

-complete income tax adjustments and benefit costs are also taken into account by the spreadsheet.

If any part of the model seems to not be working correctly, replace this copy with a newer version from the LAN.

A comprehensive users manual (APM User Manual) has been put together as a supplement to this model.

Corporate Variables are periodically reviewed and adjusted by Atmos Accounting.

Each newly released version of the APM will result in a modification to the version #.

Example: A change from Version 3.2.1 to 3.2.2 signifies that there has been a change to the Corporate Variables.

A change from Version 3.2.1 to 3.3.1 signifies that there has been an economic/calculation change to the model.

Please ensure that you are utilizing the latest version of the Profitability Model.

Company and State		Intended Tax Rate (%)	Business Unit		Overhead (%)	Stores Overhead	Ad Valorem Tax (%)	Benefits Rate (%)
1	Texas	42.20			43.06	5.00	2.48	55.60
2	Colorado	38.00			35.07	14.00	2.19	42.90
3	Kansas	38.00			33.65	14.00	3.92	42.90
4	GGC MO (old)	n/a	n/a	n/a	n/a	n/a	n/a	n/a
5	Louisiana	39.10			43.29	8.00	2.81	50.50
6	Georgia	40.00			35.10	14.00	3.24	52.00
7	Illinois	40.00			45.98	14.00	2.83	52.00
8	Iowa	40.00			51.68	14.00	3.50	52.00
9	UCG KS (OLD)	n/a	n/a	n/a	n/a	n/a	n/a	n/a
10	Missouri	40.00			51.13	14.00	2.12	52.00
11	South Carolina (OLD)	n/a	n/a	n/a	n/a	n/a	n/a	n/a
12	Tennessee	40.00			39.13	14.00	2.31	52.00
13	Virginia	40.00			53.74	14.00	0.75	52.00
14	Kentucky	41.00			42.79	20.00	1.10	52.00

capital totals- going from the year selected to the worksheet form

	Year			Year					
	21	22		21	22	23	24	25	26
w mat	0	0	w mat	0	0	#N/A	#N/A	#N/A	#N/A
mat	0	0	mat	0	0	#N/A	#N/A	#N/A	#N/A
cm lab	0	0	cm lab	0	0	#N/A	#N/A	#N/A	#N/A
ct lab	0	0	ct lab	0	0	#N/A	#N/A	#N/A	#N/A
trans	0	0	trans	0	0	#N/A	#N/A	#N/A	#N/A
row	0	0	row	0	0	#N/A	#N/A	#N/A	#N/A
ferc	0	0	ferc	0	0	#N/A	#N/A	#N/A	#N/A
other1	0	0	other1	0	0	#N/A	#N/A	#N/A	#N/A
other2	0	0	other2	0	0	#N/A	#N/A	#N/A	#N/A
other3	0	0	other3	0	0	#N/A	#N/A	#N/A	#N/A

Asset Classes

- 1 vehicles, computers, hi-tech equipment (5 year class)
- 2 furniture, fixtures, tools, office and power operated equip (7 year class)
- 3 pipe, meters, regulators, fittings, etc.. (15 year class)
- 4 buildings (real estate class)

asset ref.

3

Tax Depreciation
Book Depreciation

27	#N/A	28	#N/A	29	#N/A	30	#N/A	21	TRUE	22	TRUE	23	FALSE	24	FALSE	25	FALSE	26	FALSE	27	FALSE
	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	TRUE	TRUE	TRUE	TRUE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	TRUE	TRUE	TRUE	TRUE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	TRUE	TRUE	TRUE	TRUE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	TRUE	TRUE	TRUE	TRUE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	TRUE	TRUE	TRUE	TRUE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	TRUE	TRUE	TRUE	TRUE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	TRUE	TRUE	TRUE	TRUE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	TRUE	TRUE	TRUE	TRUE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	#N/A	TRUE	TRUE	TRUE	TRUE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE



Project: CAPD DR - 105, Main Extensions

Year	Capital Outlay	Operating Costs	Marketing Programs Cost	Refunds of Advance	Interest Expense	Ad Valorem Tax	Income Taxes	After Tax Net Income	Cash Flow	Total Load (ccf)	Return On Equity (%)
1	\$11,633.89	\$250.00	\$0.00	\$0.00	\$330.64	\$259.78	\$348.19	\$522.28	(\$10,315.62)	6700	9.35%
2	\$0.00	\$250.00	\$0.00	\$0.00	\$314.10	\$250.83	\$358.39	\$537.58	\$1,526.45	6700	10.25%
3	\$0.00	\$250.00	\$0.00	\$0.00	\$295.18	\$241.87	\$369.54	\$554.31	\$1,480.04	6700	11.24%
4	\$0.00	\$250.00	\$0.00	\$0.00	\$277.46	\$232.91	\$380.21	\$570.31	\$1,438.78	6700	12.30%
5	\$0.00	\$250.00	\$0.00	\$0.00	\$260.84	\$223.95	\$390.44	\$585.66	\$1,401.67	6700	13.44%
6	\$0.00	\$250.00	\$0.00	\$0.00	\$245.22	\$214.99	\$400.27	\$600.41	\$1,368.22	6700	14.65%
7	\$0.00	\$250.00	\$0.00	\$0.00	\$230.28	\$206.04	\$409.83	\$614.74	\$1,352.27	6700	15.99%
8	\$0.00	\$250.00	\$0.00	\$0.00	\$215.57	\$197.08	\$419.30	\$628.94	\$1,351.76	6700	17.52%
9	\$0.00	\$250.00	\$0.00	\$0.00	\$200.86	\$188.12	\$428.77	\$643.15	\$1,351.71	6700	19.28%
10	\$0.00	\$250.00	\$0.00	\$0.00	\$186.14	\$179.16	\$438.24	\$657.35	\$1,350.73	6700	21.33%
11	\$0.00	\$250.00	\$0.00	\$0.00	\$171.42	\$170.20	\$447.71	\$671.56	\$1,350.69	6700	23.74%
12	\$0.00	\$250.00	\$0.00	\$0.00	\$156.71	\$161.25	\$457.18	\$685.76	\$1,349.71	6700	26.63%
13	\$0.00	\$250.00	\$0.00	\$0.00	\$141.99	\$152.29	\$466.65	\$699.97	\$1,349.66	6700	30.16%
14	\$0.00	\$250.00	\$0.00	\$0.00	\$127.27	\$143.33	\$476.12	\$714.17	\$1,348.69	6700	34.54%
15	\$0.00	\$250.00	\$0.00	\$0.00	\$112.56	\$134.37	\$485.59	\$728.38	\$1,348.64	6700	40.16%
16	\$0.00	\$250.00	\$0.00	\$0.00	\$99.83	\$125.41	\$494.26	\$741.39	\$1,211.18	6700	45.52%
17	\$0.00	\$250.00	\$0.00	\$0.00	\$91.09	\$116.46	\$501.34	\$752.01	\$1,075.78	6700	49.72%
18	\$0.00	\$250.00	\$0.00	\$0.00	\$84.35	\$107.50	\$507.62	\$761.43	\$1,078.45	6700	54.54%
19	\$0.00	\$250.00	\$0.00	\$0.00	\$77.60	\$98.54	\$513.90	\$770.85	\$1,081.13	6700	60.24%
20	\$0.00	\$250.00	\$0.00	\$0.00	\$70.85	\$89.58	\$520.18	\$780.28	\$1,083.81	6700	67.07%
21	\$0.00	\$250.00	\$0.00	\$0.00	\$64.10	\$80.62	\$526.47	\$789.70	\$1,086.48	6700	75.42%
22	\$0.00	\$250.00	\$0.00	\$0.00	\$57.36	\$71.66	\$532.75	\$799.12	\$1,089.16	6700	85.86%
23	\$0.00	\$250.00	\$0.00	\$0.00	\$50.61	\$62.71	\$539.03	\$808.55	\$1,091.83	6700	99.28%
24	\$0.00	\$250.00	\$0.00	\$0.00	\$43.86	\$53.75	\$545.31	\$817.97	\$1,094.51	6700	117.18%
25	\$0.00	\$250.00	\$0.00	\$0.00	\$37.11	\$44.79	\$551.60	\$827.39	\$1,097.18	6700	142.24%
26	\$0.00	\$250.00	\$0.00	\$0.00	\$30.36	\$35.83	\$557.88	\$836.82	\$1,099.86	6700	179.82%
27	\$0.00	\$250.00	\$0.00	\$0.00	\$23.62	\$26.87	\$564.16	\$846.24	\$1,102.54	6700	242.46%
28	\$0.00	\$250.00	\$0.00	\$0.00	\$16.87	\$17.92	\$570.44	\$855.66	\$1,105.21	6700	367.75%
29	\$0.00	\$250.00	\$0.00	\$0.00	\$10.12	\$8.96	\$576.73	\$865.09	\$1,107.89	6700	743.59%
30	\$0.00	\$250.00	\$0.00	\$0.00	\$3.37	\$0.00	\$583.01	\$874.51	\$1,110.56	6700	#####

Tennessee Public Service Company
Revenue Deficiency (Surplus)
For the 12 Months Ended September 30, 2006

<u>Line No.</u>		
1	Rate Base	155,848,893
2	Operating Income at Present Rates	16,377,3105
3	Earned Rate of Return (L2 / L1)	10.51%
4	Fair Rate of Return	7.41%
5	Required Operating Income (L1 X L4)	11,548,403
6	Operating Income Deficiency (Surplus)(L5 - L2)	(4,828,702)
7	Gross Revenue Conversion Factor	<u>1.635949</u>
8	Revenue Deficiency (Surplus)	<u><u>(7,899,509)</u></u>

STATE OF MICHIGAN
DEPARTMENT OF ATTORNEY GENERAL



MIKE COX
ATTORNEY GENERAL

P.O. Box 30212
LANSING, MICHIGAN 48909

November 13, 2006

Ms. Mary Jo Kunkle
Executive Secretary
Michigan Public Service Commission
6545 Mercantile Way
Lansing, MI 48911

Dear Ms. Kunkle:

RE: MPSC Case No. U-14893

Enclosed for filing in the above-captioned case please find the **Direct Testimony and Exhibits of David E. Dismukes, Ph.D. on Behalf of the Michigan Attorney General**, together with a proof of service. This filing is being submitted electronically pursuant to the Commission's Paperless Electronic Filings Program.

Sincerely,

A handwritten signature in cursive script, appearing to read "Michael E. Moody".

Michael E. Moody (P51985)
Assistant Attorney General
Tobacco and Special Litigation Division
(517) 373-1123

MEM:wjc
Enclosures
c: All Parties

PROOF OF SERVICE - U-14893

The undersigned certifies that a copy of the **Direct Testimony and Exhibits of David E. Dismukes, Ph.D. on Behalf of the Michigan Attorney General**, was served upon the parties listed below by mailing the same to them at their respective addresses with first class postage fully prepaid thereon on the 13th day of November, 2006.

Wendy J. Cadwell

MPSC Staff:

Patricia S. Barone (P29560)
Assistant Attorney General
Public Service Division
6545 Mercantile Way, Suite 15
Lansing, MI 48911

Association of Businesses Advocating

Tariff Equity:

Robert A.W. Strong
Clark Hill
255 South Old Woodward Avenue
3rd Floor
Birmingham, MI 48009

Haran Rashes
Clark Hill
212 E. Grand River Avenue
Lansing, MI 48906

SEMCO Energy Gas Co:

Stewart A. Binke
Al Ernst
Dykema Gossett
Capitol View
201 Townsend, Suite 900
Lansing, MI 48933

Administrative Law Judge:

Sharon L. Feldman
MPSC – ALJ's Division
6545 Mercantile Way, Suite 14
Lansing, MI 48911

Michigan Technological University:

Michael J. Brown
Carlin, Edwards, Brown & Howe
6017 W. St. Joe Hwy., Suite 202
Lansing, MI 48917

STATE OF MICHIGAN
BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

IN THE MATTER OF:

SEMCO Energy Gas Company for)
Authority to Redesign and Increase)
Its Rates for the Sale and)
Transportation of Natural Gas In Its)
MPSC Division and for Other Relief)

Case Number U-14893

DIRECT TESTIMONY
OF
DAVID E. DISMUKES, PH.D.

ON BEHALF OF THE
MICHIGAN ATTORNEY GENERAL

DIRECT TESTIMONY OF
DAVID E. DISMUKES, PH.D.
ON BEHALF OF THE
MICHIGAN ATTORNEY GENERAL
CASE NUMBER U-14893

I. INTRODUCTION

Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS ADDRESS?

A. My name is David E. Dismukes. My business address is 6455 Overton Street, Baton Rouge, Louisiana.

Q. WOULD YOU PLEASE STATE YOUR OCCUPATION AND CURRENT PLACE OF EMPLOYMENT?

A. I am a Consulting Economist with the Acadian Consulting Group ("ACG"), a research and consulting firm that specializes in the analysis of regulatory, economic, financial, accounting, statistical, and public policy issues associated with regulated and energy industries. ACG is a Louisiana-registered partnership, formed in 1995, and is located in Baton Rouge, Louisiana with additional staff in Los Angeles, California, and Carson City, Nevada.

Q. HAVE YOU PREPARED ANY ATTACHMENTS TO YOUR TESTIMONY OUTLINING YOUR QUALIFICATIONS IN ENERGY AND REGULATED INDUSTRIES?

A. Yes. Attachment 1 to my testimony provides my academic vita that includes a full listing of my publications, presentations, and pre-filed expert

1 witness testimony, expert reports, expert affidavits, and legislative testimony.

2 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?**

3 A. I have been retained by Michigan Attorney General (“AG”) to review the
4 application submitted by SEMCO Energy Gas Company (“SEMCO” or “the
5 Company”) to redesign and increase its rates for the sale and transportation of
6 natural gas to customers in its Michigan Public Service Commission (“MPSC”)
7 jurisdiction. In particular, I have been asked to provide an expert opinion on: (1)
8 the Company’s proposal to adopt a straight-fixed variable (“SFV”) rate design; (2)
9 the Company’s requested changes in the ratemaking treatment of Lost and
10 Unaccounted for Gas (“LAUF”) and uncollectibles expense; and (3) the
11 Company’s proposal to change its weather normalization period from 30 to 15
12 years.

13 **Q. HOW IS THE REMAINDER OF YOUR TESTIMONY ORGANIZED?**

14 A. My testimony is organized into the following sections:

- 15 • Section II: Summary of Recommendations
- 16 • Section III: Description of Revenue Neutrality
- 17 • Section IV: Utility Motivation for Promoting Revenue Neutrality
- 18 • Section V: Negative Impacts to Ratepayers from Revenue Neutrality
- 19 • Section VI: The Company’s Proposed SFV is the Worst Kind of
20 Revenue Neutrality Proposal
- 21 • Section VII: State Regulatory Decisions on Revenue Neutrality
- 22 • Section VIII: Examination of the Company’s DSM Proposals
- 23 • Section IX: Weather Normalization

- 1 • Section X: Financial Issues Driving SEMCO's Revenue Neutrality
- 2 Proposal
- 3 • Section XI: The Company's LAUF and Uncollectibles Proposal
- 4 • Section XII: Conclusions and Recommendations

5 **II. SUMMARY OF RECOMMENDATIONS**

6 **Q DO YOU BELIEVE THAT THIS PROCEEDING HAS SIGNIFICANT**
7 **PRECEDENT-SETTING IMPLICATIONS?**

8 A Yes. While SEMCO may be a relatively small investor-owned local
9 distribution company ("LDC") in Michigan, and its proposals may seem relatively
10 harmless for a smaller utility, adoption of many of the Company's rate re-design
11 proposals will have important precedent-setting implications for the other, much
12 larger LDCs in the state. The Company's rate redesign proposals are some of
13 the more controversial topics being debated in gas regulation now across the
14 U.S. These proposals include revenue neutrality, proposals for quicker and more
15 certain recovery of uncollectibles and lost and unaccounted for gas ("LAUF"), as
16 well as for more favorable weather normalizations of billing determinants. These
17 proposals on their own provide ratepayers with little to no benefits. They are,
18 however, highly coveted by many utilities wishing to reduce risk, and pacify Wall
19 Street equity and financial analysts.

20 **Q. WOULD YOU PLEASE SUMMARIZE YOUR RECOMMENDATIONS?**

21 A. My recommendations on the Company's proposed rate re-design and
22 demand-side management programs can be summarized as follows:

- 23 • The Commission should reject the Company's proposed straight-fixed

1 variable ("SFV") rate design. The SFV proposal would result in clear
2 benefits to utility shareholders without any commiserate benefit for
3 ratepayers. The proposed rate design is inconsistent with most residential
4 rate design practices in the U.S., could result in utility inefficiencies, does
5 not promote energy efficiency, and is clearly inequitable as it has been
6 proposed.

- 7 • The Commission should completely reject the Company's proposed DSM
8 plan and its associated \$2.0 million revenue requirement. The plan
9 provides no energy savings estimates or goals and is very loosely defined.
10 Most importantly, the plan is not based upon any finding of cost-
11 effectiveness and has no accountability. Further, this DSM plan does not
12 stand as an appropriate counterbalance to the Company's SFV rate
13 design proposal.
- 14 • The Commission should reject the Company's proposal to move from a
15 30-year to 15-year weather normalization. The Company has provided no
16 compelling evidence for movement to a shorter historic period. Further,
17 movement to 15-year normalization periods is a proposal that has been
18 rejected by the Commission in the past for other utilities.
- 19 • The Commission should reject the Company's proposed annual true-up of
20 uncollectibles expense (i.e., collection of annual differences between the
21 levels included in base rates and actuals). Truing up these expenses on
22 an annual basis would result in selective ratemaking and could result in
23 inefficiencies since the incentive to hold these costs in check could be

1 reduced. Further, the Commission has rejected similar types of proposals
2 in the very recent past, and should continue to do so in this proceeding.

- 3 • The Commission should reject the Company's proposed recovery of LAUF
4 in its gas cost recovery ("GCR") rate, as well as its alternative proposal to
5 true these up on an annual basis. Collection of these costs in the GCR
6 could create inefficiencies since annual true-ups could minimize the
7 incentive to limit outstanding balances. Further, the Commission has
8 rejected similar types of proposals in the very recent past, and should
9 continue to do so in this proceeding.

10 **III. DESCRIPTION OF REVENUE NEUTRALITY**

11 **Q WOULD YOU PLEASE DISCUSS THE COMPANY'S RATE RE-DESIGN**
12 **PROPOSALS?**

13 A The Company is proposing to dramatically change the manner in which it
14 charges its customers for distribution service. Common utility pricing practice is
15 typically based upon what is referred to as a "two-part tariff." This two-part tariff
16 is comprised of a fixed customer charge and a per unit (volumetric) charge.
17 Natural gas commodity charges are also variable, and applied to customers' bills
18 on a usage basis. The Company is proposing a rather dramatic change in the
19 way customers are charged for distribution service. Under the Company's
20 proposal, all distribution charges will be applied on a fixed basis rather than the
21 commonly accepted two-part approach. The only variable charge the customer
22 will see is the commodity gas charges recovered through the gas cost recovery
23 ("GCR") rate. This substantial revision in rate design is often referred to as a

1 “straight-fixed variable” or “SFV” rate design since all fixed costs are recovered in
2 a customer charge, and commodity charges are recovered on a variable basis.

3 **Q WHAT ARE THE STATED PURPOSES FOR THIS RATE RE-DESIGN?**

4 A The Company has given three reasons for its proposed rate design
5 changes. The first justification is based upon an economic efficiency argument.
6 That is, the Company believes that moving to a SFV rate design will result in
7 greater economic efficiency. The second justification is based upon the
8 Company’s concerns regarding its ability to earn its authorized rate of return.
9 These concerns are based upon what the Company believes are continued and
10 ongoing decreases in use per customer that challenge its ability to collect its
11 authorized revenues. The third reason is based upon energy efficiency. The
12 Company believes that its proposed SFV will help remove the disincentive it has
13 for actively promoting energy efficiency and demand side management (“DSM”).

14 **Q PLEASE EXPLAIN THE ECONOMIC EFFICIENCY ARGUMENT.**

15 A The Company notes that a good portion of the cost of providing gas
16 distribution service is fixed. Rates, however, are charged on a combination of
17 fixed and variable charges. The Company argues that this is an inefficient rate
18 design since “optimally,” fixed costs should be recovered only under fixed
19 charges and variable costs should be recovered only under variable charges. By
20 moving all charges to a fixed basis, the Company argues that its rate design is
21 more economically efficient since it would be based upon more “sound economic
22 principles” than the currently utilized rate design.

23 **Q WHAT ABOUT THE FINANCIAL CHALLENGES ARGUMENT?**

1 A The Company, as well as many other natural gas LDCs have argued that
2 greater end user efficiency in natural gas usage has created financial challenges
3 for these companies in earning their authorized rates of return. In particular,
4 LDCs have argued that longer-run decreases in the use per customer
5 (particularly for residential customers), most of which has been created by a
6 combination of customer-initiated energy efficiency, changing building codes,
7 changing appliance standards, and the natural customer reaction to changes in
8 things like price, income and weather, have challenged their ability to earn their
9 authorized rates of return. The argument being made by many LDCs, and one
10 that is also made by the Company in this proceeding, is that decreases in use
11 per customer will result in the collection of revenues lower than those included in
12 their typical test year for rate making purposes. The argument is that if costs are
13 relatively fixed, then the decrease in revenues will result in challenges for LDCs
14 in earning their authorized rate of return.

15 **Q WHAT ABOUT THE ENERGY EFFICIENCY ARGUMENT?**

16 A The Company, and many LDCs, have argued that since a large portion of
17 their distribution non-gas ("DNG" or "base") revenues are tied to usage through
18 volumetric charges, they have little to no incentive to promote energy efficiency
19 through the development of demand-side management ("DSM") programs. Many
20 LDCs promoting revenue neutrality proposals before regulatory commissions
21 have been arguing that the sales loss associated with these DSM programs will
22 result in decreased earnings. Many utilities have argued they are either unwilling

1 or unable to address significant energy efficiency opportunities until this structural
2 rate design challenge is addressed.

3 **Q DO YOU AGREE WITH THE COMPANY'S POSITIONS ON ITS**
4 **PROPOSED RATE RE-DESIGN?**

5 A No, it is not clear that the dramatic changes in rate design being proposed
6 by the Company will result in marked improvements in efficiency nor is it clear
7 that these changes will result in a new, more passionate acceptance of energy
8 efficiency. What is clear is that the Company's shareholders will benefit
9 significantly from a reduction in sales risk created by this form of rate design.

10 **Q DO YOU THINK THERE ARE SOME SPECIAL CONSIDERATIONS THE**
11 **COMMISSION SHOULD KEEP IN MIND IN REVIEWING THE COMPANY'S**
12 **PROPOSALS?**

13 A Yes, the SFV proposal, in addition to several others proposed in the
14 Company's filing, are exceptionally precedent-setting in nature and the
15 ramifications of accepting these proposals go well beyond SEMCO despite it
16 being a relatively small investor-owned utility in Michigan. The Company's rate
17 re-design proposals are some of the more controversial issues being debated at
18 regulatory commissions across the U.S. As I will discuss later, equity and other
19 financial analysts are placing high expectations upon LDCs that are able to
20 secure regulatory approval for revenue neutrality programs (like revenue
21 decoupling and/or SFV rate designs) in addition to other risk-reducing programs
22 like weather normalization clauses, more favorable LAUF and uncollectibles
23 recovery, and shorter weather normalization periods. Clearly, utilities that obtain

1 these types of risk-mitigating measures, particularly those that obtain these
2 measures without making substantial concessions on their allowed return on
3 equity ("ROE"), obtain higher Wall Street approval.

4 **Q IS REVENUE NEUTRALITY A NEW IDEA?**

5 A No, as a regulatory concept, revenue neutrality has been around for quite
6 some time and is a policy that was first promoted in the electric power industry
7 well over a decade ago. In fact, the first Energy Policy Act (of 1992) addressed
8 revenue neutrality and required states to consider this mechanism in conjunction
9 with integrated resource planning ("IRP") standards stressing the use of demand-
10 side resources in a manner comparable to traditional supply-side considerations.
11 The purported goals of revenue neutrality policies then, as well as now, were to
12 develop rate design approaches that supposedly make a utility indifferent
13 between promoting energy efficiency and sales. Since the early 1990s, a variety
14 of different approaches to revenue neutrality have been adopted. The primary
15 revenue neutrality methods being promoted in the natural gas industry include
16 what is referred to as "revenue decoupling" (and its various different forms) and
17 the use of what is referred to as "straight-fixed variable" ("SFV") rate design
18 mechanisms (or variations on something akin to the SFV rate design idea).

19 **Q HAS REVENUE NEUTRALITY BEEN WIDELY ADOPTED SINCE THE**
20 **PASSAGE OF EPACT 1992?**

21 Q No. The original impetus for revenue neutrality was in the electric power
22 industry and a combination of competition, a decades-long boom in the U.S.
23 economy, and low fossil fuel prices worked to diminish interest in revenue

1 decoupling throughout most of the 1990s. Recent increases in fossil fuel prices,
2 particularly natural gas, have renewed interest in this ratemaking concept,
3 particularly for natural gas LDCs.

4 **Q EARLIER YOU MENTIONED REVENUE DECOUPLING AS A FORM OF**
5 **REVENUE NEUTRAL RATE DESIGN. CAN YOU EXPLAIN THIS IN**
6 **GREATER DETAIL?**

7 A Yes, revenue decoupling is a form of revenue neutrality that changes the
8 manner in which revenues are collected from ratepayers. Typically base rates
9 are fixed and based upon a fixed allowed rate of return (among other factors).
10 While the allowed revenues included in this formula are considered fixed, the
11 actual revenues can, and often do, vary from year-to-year depending upon a
12 wide range of factors. Revenue decoupling basically changes the nature of this
13 process. Under a revenue decoupling regime, revenues are fixed and virtually
14 guaranteed while rates are allowed to vary from year-to-year to assure this
15 guaranteed level of revenue recovery.

16 **Q HOW DOES REVENUE DECOUPLING WORK?**

17 A Revenue decoupling is typically done on a revenue per customer basis.
18 Under a typical revenue decoupling approach, an allowed revenue per customer
19 is taken from a rate case, or agreed upon level. This allowed revenue per
20 customer is then determined for every month of the year. As time progresses,
21 the allowed revenue per customer is compared to the actual revenue per
22 customer. If actual revenues are lower than allowed, the revenue short-fall is
23 booked to a true-up account to be factored into rates. These true-ups can occur

1 as frequently as every month, every quarter, or annually. The process is
2 symmetrical – if revenues are greater than allowed, excess revenues are
3 credited to the balancing account for a future rate decrease.

4 **Q CAN REVENUE DECOUPLING TAKE DIFFERENT FORMS?**

5 A Yes, there are two general forms of revenue decoupling: full revenue
6 decoupling and partial revenue decoupling. Full decoupling allows the entire
7 under or over-recovery of revenues to fall into a balancing account for later true
8 up. Partial decoupling only allows some part of that overage/underage to enter
9 the balancing account. In some instances, the balances are adjusted for
10 changes in prices, weather, and/or the economy. That is, price-related, weather-
11 related, or economic-related changes in revenues are not eligible for recovery in
12 the balancing account. This process can also be referred to as “statistical re-
13 coupling” since estimates from statistical load forecasts are used to make the
14 price, weather, and economic-related adjustments. Another form of partial
15 decoupling can occur through a fixed cap percent on revenue recovery. North
16 Carolina and Oregon for instance, have caps on total decoupling balance
17 recoveries. The current interim approach being used in Utah also has a cap on
18 total revenues that can be recovered in the decoupling balancing account.

19 **Q ARE SFV AND REVENUE DECOUPLING RELATED?**

20 A Somewhat. Revenue decoupling usually preserves the traditional rate
21 design structure utilized by most regulatory commissions around the U.S.
22 Namely, distribution service rates are comprised of a fixed customer charge and
23 a volumetric distribution charge. Revenue decoupling sets a target revenue per

1 customer level to be recovered under these rates: if actual recovery falls below
2 the target, then rates are increased in a subsequent period to make up for the
3 short fall and vice versa. Thus, one can think of revenue decoupling as creating
4 a true-up process that sets variable rates at a level that makes customers
5 indifferent between them being fixed or variable. SFV can be thought of as
6 “perfect revenue decoupling” since rates are not required to be “trued-up” in any
7 given year and are directly (not indirectly) charged to customers on a fixed per-
8 customer basis.

9 **IV UTILITY MOTIVATION FOR PROMOTING REVENUE NEUTRALITY**

10 **Q WHAT DO YOU THINK IS MOTIVATING LDCS TO PROPOSE SUCH**
11 **DRAMATIC RATE DESIGN CHANGES LIKE A SFV OR REVENUE**
12 **DECOUPLING?**

13 A These revenue neutrality proposals appear to be more a reflection of the
14 times, and changes in gas markets, than they are major initiatives to promote
15 economic or energy efficiency. While the promotion of energy efficiency can be
16 important for many LDCs, as it can be for numerous electric utilities, there are a
17 number who have developed DSM programs without the benefit of any revenue
18 neutrality programs. It appears that the recent rush to such proposals as SFV
19 and revenue decoupling, however, are a function of increases in gas prices,
20 which raises concerns in the financial community. Many financial analysts and
21 others groups representing the financial community have either directly or
22 indirectly helped promote a number of these risk mitigation proposals before
23 regulatory commissions.

1 **Q WHAT TYPES OF PROGRAMS APPEAR TO BE MOST ENCOURAGED**
2 **BY THE FINANCIAL COMMUNITY?**

3 A There are a number of favored programs that include the adoption of gas
4 recovery clauses, weather normalization clauses, shorter weather normalization
5 periods, and pass-through recovery of LAUF and uncollectibles expense.
6 Revenue neutrality, in the form of revenue decoupling or SFV rate designs,
7 however, appears to be the most popular regulatory mechanism with many of
8 these analysts (with the exception of the few utilities that do not have GCRs).
9 These analysts see revenue neutrality mechanisms as being beneficial to
10 shareholders by reducing overall risk. Many financial analysts are starting to
11 preference the ratings and categorizations of those companies that have such
12 policies in place.

13 **Q DO YOU HAVE ANY EXAMPLES?**

14 A Yes, Moody's Investor Service ("Moody's"), in a June 2005 Special
15 Comment on natural gas utilities, noted:

16 "Moody's believes that having utility rate designs that
17 compensate the gas LDC for variations in conservation as with
18 variations in weather would serve to stabilize the utility's credit
19 metrics and credit ratings."¹

20 Further, Moody's indicated that revenue decoupling can impact the business risk
21 categorization under which utilities are judged by Standard and Poor's. This
22 categorization, based upon business risk profiles, includes a measure for utilities
23 that face supply and volumetric risk. Those with high risk are in the higher
24 categories (highest risk category is 10), while those utilities that face lower risks

¹ *Special Comment: Impact of Conservation on Gas Margins and Financial Stability in the Gas LDC Sector*, Moody's Investors Services, June, 2005: 8.

1 by having adjustment clauses, are moved to lower levels. NW Natural, a gas
2 distribution utility in Oregon that has both a GCR and decoupling mechanism,
3 was able to lower its rank to 1, the lowest level category.

4 **Q DOES REVENUE DECOUPLING HAVE ANY POTENTIAL IMPACT ON**
5 **DEBT?**

6 A Yes. Moody's recently reiterated the strong benefits revenue decoupling
7 would provide in maintaining shareholder value. Such a mechanism will maintain
8 strong credit metrics and improve credit ratings relative to utilities that do not
9 have such mechanisms since revenue decoupling eliminates shareholder
10 exposure to risk and volatility from price and climate changes.² Further,
11 according to a recent review of the NW Natural decoupling program:

12 "[NW Natural] CFO David Anderson believes that DMN
13 [Distribution Margin Normalization] and WARM [Weather
14 Adjusted Rate Mechanism] were contributing factors to NW
15 Natural obtaining the best rating in the Standard & Poor's (S&P)
16 business risk profile (scoring a 1 on a scale of 1 to 10). Similarly,
17 he believes that DMN and WARM contributed to the upgrade in
18 NW Natural's S&P bond rating from A to A+. An improved risk
19 profile has several beneficial effects. It allows NW Natural to
20 maintain smaller lines of credit, reduce the share of equity in its
21 capital structure, and maintain a lower coverage ratio."³

22 **V NEGATIVE IMPACTS TO RATEPAYERS FROM REVENUE**
23 **NEUTRALITY**

24 **Q ARE THESE FORMS OF REVENUE NEUTRALITY GENERALLY**
25 **SUPPORTED BY CONSUMER GROUPS?**

26 A No, while there are some exceptions, most revenue neutrality proposals
27 tend to not be widely supported by consumer groups of all types. This includes

² *Special Comment: Local Gas Distribution Companies: Update on Revenue Decoupling and Implications for Credit Ratings*, Moody's Investor Services, June 2006.

³ *A Review of Distribution Margin Normalization as Approved by the Oregon Public Utility Commission for Northwest Natural Gas*, Christensen and Associates, March 31, 2005: 72.

1 not only residential and small commercial customers, but low income customers,
2 and in some instances larger commercial and industrial customers.

3 **Q CAN REVENUE DECOUPLING HAVE ANY NEGATIVE IMPLICATIONS**
4 **FOR RATEPAYERS?**

5 A Yes, revenue neutrality proposals can have a number of negative
6 implications for ratepayers including shifting a wide range of traditional business
7 risk away from shareholders and towards ratepayers. This includes risks
8 associated with changes in the economy, changes in commodity prices, and in
9 some instances, changes in weather. Those proposals that fail to account for
10 this risk shifting, through some type of adjustment mechanism, can impose a cost
11 onto ratepayers without any corresponding benefit.

12 **Q. HOW DO TYPICAL REVENUE NEUTRALITY PROPOSALS SHIFT RISK**
13 **AWAY FROM UTILITIES AND TOWARDS CUSTOMERS?**

14 A. Risk is shifted to customers through the revenue per customer true-up
15 mechanism. This mechanism provides utilities with a **guaranteed** revenue per
16 customer amount. Current regulatory approaches only give utilities an
17 **opportunity** to earn typical revenues, but do not guarantee that recovery. Under
18 current rate design, customers have the opportunity to avoid a portion of their
19 distribution non-gas charges if they conserve (lower consumption) or adopt
20 energy efficient appliances and other measures. This will not be the case under
21 this Company's proposals which will essentially require all customers to pay a
22 fixed, non-bypassable charge for distribution service. If the Company's SFV

1 proposals are accepted, customers who conserve natural gas will have all of their
2 distribution cost savings stripped away from them and returned to the Company.

3 **Q. WHAT TYPES OF FACTORS IMPACT REVENUE RECOVERY UNDER**
4 **TRADITIONAL REGULATORY APPROACHES?**

5 A. A number of factors can influence sales including economic conditions,
6 gas commodity prices, weather, and other unanticipated events that impact
7 usage. Under traditional regulation, these risks are usually borne by the utility,
8 not by ratepayers. Under the Company's proposals, these risks are entirely
9 shifted onto ratepayers since there is no means for them to reduce their
10 distribution charges by reducing usage in the face of decreasing economic
11 conditions, higher prices, warmer weather, and other factors.

12 **Q. HOW ARE ECONOMIC RISKS SHIFTED TO RATEPAYERS?**

13 A. If revenues decline due to a contraction in the economy, customers will be
14 required to make the utility whole for those revenue shortfalls. Decreases in
15 sales associated with economic downturns have nothing to do with energy
16 efficiency or a DSM program promoted by the Company. Instead, they are the
17 natural reaction of households trying to reduce their expenditures during difficult
18 economic times. Under the Company's rate design "improvements," customers
19 will be required to make a utility whole for what could have been revenue losses
20 during these economic downturns, whereas under traditional regulation, this
21 would not have been the case.

1 **Q. ARE THERE ANY REAL-WORLD EXAMPLES OF HOW REVENUE**
2 **NEUTRALITY PROGRAMS CREATED SERIOUS PROBLEMS DURING AN**
3 **ECONOMIC CONTRACTION?**

4 A. Yes, one of the more widely-recognized failures of revenue decoupling
5 occurred in Maine during the early 1990s. The program, known as “ERAM”
6 (“Electric Revenue Adjustment Mechanism”), was put into place for a three year
7 trial period to encourage Central Maine Power (“CMP”) to promote DSM. The
8 ERAM had no adjustments for changes in regional activity. The adoption of the
9 ERAM coincided with a recession that resulted in lower sales levels and
10 substantial revenue deferrals. CMP was entitled to recover these deferrals under
11 the provisions of the ERAM mechanism, which by the end of 1992 reached \$52
12 million. Only a very small portion of this amount was attributed to CMP’s
13 conservation efforts as most of the deferral resulted from the economic
14 recession. The ERAM was viewed by many as a mechanism that shielded CMP
15 from the economic impact of the recession rather than furthering the intended
16 energy efficiency and conservation incentives. CMP’s ERAM was terminated on
17 November 30, 1993.⁴

18 **Q. COULD THE RATE DESIGN PROPOSALS OFFERED BY THE**
19 **COMPANY CREATE THE SAME KINDS OF PROBLEMS AS THOSE**
20 **EXPERIENCED IN MAINE?**

⁴*Report on Utility Incentives Mechanisms for the Promotion of Energy Efficiency and System Reliability*, Maine Public Utilities Commission, Presented to the Utilities and Energy Committee, February 1, 2004, Internet Website:
http://www.maine.gov/mpuc/staying_informed/legislative/2004legislation/Eff-Rel%20Report-final.htm

1 A. Yes. The proposed fixed rate design has no true up provisions and makes
2 no allowances or adjustments for changes in economic activity, positively or
3 negatively. If the Commission adopts the Company's proposed SFV rate design,
4 and the economy underperforms on a forward-going basis, ratepayers will bear
5 the risk of those economic downturns since they will be paying a constant
6 customer charge. As a result, they will be unable to reduce their non-gas
7 distribution charges by decreases in consumption since the charges placed upon
8 them are fixed. This differs from current rate design practices in Michigan, and
9 throughout most of the U.S., where customers could reduce both the gas and
10 non-gas portions of their bills by reduced consumption during challenging
11 economic periods.

12 **Q HOW DOES THIS RELATE TO THE CURRENT TRENDS IN THE**
13 **MICHIGAN ECONOMY?**

14 A The Michigan economy has seen a number of recent challenges over the
15 past several years, particularly in manufacturing, and in particular, in automobile
16 manufacturing. Ratepayers will be required to absorb all continued risk
17 associated with any future downturns and challenges in the Michigan economy if
18 the Company's SFV is adopted. Exhibit AG-1 shows the increasing level of
19 unemployment in the Michigan economy over the past five years. While the U.S.
20 total non-farm unemployment rate for September 2006 was at 4.6 percent, the
21 Michigan level is higher at 7.1 percent. Further, Michigan has lost more jobs
22 over the past 5 years than any other state. A rank order of total job losses since
23 2000 has been provided in Exhibit AG-2.

1 **Q HOW WOULD YOU CHARACTERIZE CURRENT AND PROJECTED**
2 **TRENDS IN THE U.S. ECONOMY?**

3 A Many economic analysts see a downward bias in future economic activity
4 over the next year given recent downturns in housing and automobile
5 manufacturing in the U.S. The degree and extent of this future downturn,
6 however, is debated. Most analysts see a slowing of economic growth while
7 others see an outright recession. Many analysts and advisory services have
8 already begun to revise their economic forecasts to reflect this anticipated
9 underlying weakness. Exhibit AG-3 shows some recent GDP forecast revisions
10 for the economy that have been made publicly available over the past several
11 months.

12 **Q WHAT ABOUT U.S. MANUFACTURING ACTIVITY?**

13 A In addition to overall economic softening, there are some continued
14 concerns about U.S. industrial and manufacturing activity. Overall industrial
15 activity has started turning down as evidenced in Exhibit AG-4 which shows
16 recent trends in the industrial production index. Exhibit AG-5 shows
17 manufacturing capacity utilization which has also started decline. Further, the
18 recent report issued by the Institute of Supply Managers ("ISM") Index of
19 manufacturing activity has taken a marked downturn. While the index is still
20 above 50, indicating continued expansion, it is at a level much lower than the
21 past several years. These readings are particularly important for state
22 economies like Michigan that rely relatively heavily upon manufacturing activity
23 as a source of economic output and growth.

1 **Q WHO WILL BEAR THE ONGOING RISK OF ECONOMIC DOWNTURNS**
2 **IF THE COMPANY'S SFV PROPOSAL IS ACCEPTED?**

3 A Ratepayers will bear the full risk of revenue changes from decreases in
4 regional economic activity if the Company's proposed SFV is adopted. In the
5 past, the Company would have to manage this risk and adopt other measures,
6 such as cost efficiencies, or promoting customer growth or usage in other areas,
7 to offset any economic downturns. The SFV, however, will virtually guarantee
8 total revenue recovery holding the number of customers constant. Timing the
9 adoption of a SFV, or any other type of revenue neutrality proposal, in an
10 environment that has a downward bias in economic activity is exceptionally
11 inopportune.

12 **Q HAS THE COMPANY RECOGNIZED THESE ECONOMIC**
13 **CHALLENGES?**

14 A Yes. The testimony provided by many of the Company's experts clearly
15 recognizes the economic challenges being faced in the region and Exhibit AG-6
16 highlights a number of quotations recognizing these economic challenges.

17 **Q. HOW IS COMMODITY PRICE RISK SHIFTED TO CUSTOMERS?**

18 A. When gas commodity prices increase, customers tend to reduce
19 consumption. In fact, it is likely that some portion of the decreases in use per
20 customer highlighted throughout the Company's application are the result of
21 price-induced reductions in consumption created by recent increases in natural
22 gas prices over the past 5 to 6 years. These reductions in usage have nothing to
23 do with any DSM activities undertaken by the Company, but reflect customer-

1 initiated actions to either reduce usage or increase efficiency. By adopting a SFV
2 rate design, the Company would like to be compensated for energy efficiency
3 efforts made entirely by customers on a forward going basis.

4 **Q WOULD THE COMPANY'S PROPOSED SFV RATE DESIGN SHIFT**
5 **ANY WEATHER-RELATED RISK TO CUSTOMERS?**

6 A Yes. Since the Company's SFV rate design is usage "in-sensitive," there
7 will be no change in Company revenues due to changes in the weather. This is a
8 significant shift of risk away from the Company's shareholders and onto its
9 ratepayers. The proposed SFV will effectively allow the Company to obtain both
10 a revenue decoupling and weather normalization clause ("WNC") all in one
11 proposal. One could make the argument that weather-related changes in
12 demand can be symmetrical: in instances where sales are colder than normal,
13 ratepayers will be better off since revenues will increase relative to the test year.
14 The opposite would occur if the weather is anticipated to be warmer than normal.
15 However, the Company's filing clearly shows that it anticipates the climatological
16 bias being in the direction of warmer-than-normal weather, rather than colder-
17 than-normal weather. If the Company is correct, then the WNC-type attributes of
18 the SFV would provide a direct benefit to its shareholders at customers' expense
19 without any corresponding adjustment for that shifting in risk being reflected in
20 rates.

21 **Q WHY WOULD YOU CONCLUDE THAT THE COMPANY PERCEIVES A**
22 **WARMER-THAN-NORMAL WEATHER BIAS?**

1 A The Company has an alternative recommendation that includes changing
2 the weather normalization period for ratemaking purposes from 30 years to 15
3 years. Since the average number of heating degree days (“HDDs”) in the past
4 15-year average is lower than the past 30-year average, there is clear bias in
5 favor of a warmer-than-normal winter weather trend in the Company’s alternative
6 proposal. As I will discuss later in my testimony, this adjustment is equally
7 unwarranted and should be dismissed by the Commission in conjunction with the
8 Company’s proposed SFV.

9 **Q HAS THE COMMISSION RECOGNIZED THE POTENTIAL FOR RISK-**
10 **SHIFTING IN REVENUE NEUTRALITY PROPOSALS BEFORE?**

11 A Yes. There is an additional revenue neutrality method that can be used by
12 states in the DSM process which is known as “lost revenue recovery.” This
13 method usually allows utilities to recover the lost revenue they have incurred
14 from promoting DSM under certain strict, verifiable conditions. Michigan, in fact,
15 has chosen this form of revenue neutrality in the past and allowed electric utilities
16 to recover lost revenues under certain strict conditions. The Commission’s full
17 policy, which was adopted from a Staff Recommendation, is clearly articulated in
18 several orders and notes that utilities **should not be allowed** to recover losses in
19 sales that have resulted from “changes in the weather, economic trends, or other
20 factors.”^{5,6} Thus, the Commission has explicitly recognized that revenue

⁵ In the matter of the application of Consumers Power Company for authority to increase its rates for the sale of electricity, Case No. U-10335, Michigan Public Service Commission, May 10, 1994.

⁶ On the matter of the proceeding, on the Commission’s own motion to examine the electric rates of Consumers Power Company; In the matter of the complaint of the Association of Businesses Advocating Tariff Equity against Consumers Power Company with respect to its

1 neutrality, if adopted, should not result in changes in the risk sharing
2 relationships between utilities and ratepayers. The Company's SFV proposal is
3 clearly inconsistent with the Commission's prior policy.

4 **Q DO YOU THINK THAT THE COMPANY'S SFV PROPOSAL CAN**
5 **RESULT IN FAIR, JUST, AND REASONABLE RATES?**

6 A. No. The Company's proposed SFV rate design will result in a significant
7 amount of risk being shifted away from itself and its shareholders, and onto
8 ratepayers. These risks include potential changes in price, the economy,
9 weather, and other factors like greater economy-wide energy efficiency. These
10 potential variations probably account for over 90 percent of the Company's
11 revenue variability. However, the Company has made no corresponding offset in
12 rates, particularly in its recommended allowed rate of return. Failing to recognize
13 the risk-shifting inherent in this rate design proposal would result in rates that, by
14 definition, were not fair, just, and reasonable and would allow the utility to claw
15 into the very monopoly profits that regulation is intended to control.

16 **VI THE COMPANY'S PROPOSED SFV IS THE WORST KIND OF**
17 **REVENUE NEUTRALITY PROPOSAL**

18 **Q WHY DO YOU BELIEVE SFV IS THE WORST FORM OF REVENUE**
19 **NEUTRALITY PROPOSAL BEING CONSIDERED BY LDCS?**

20 A The SFV rate design creates some of the largest inefficiencies and
21 inequities of any of the revenue neutrality proposals currently being considered
22 across the country. In addition to creating inefficiencies and inequities, the SFV

electric rates, Case No. U-9346, Michigan Public Service Commission, September 25, 1991
(Settlement attached).

1 does nothing to promote energy efficiency and, in fact, is usually not supported
2 by energy efficiency advocates around the country. The SFV serves only one
3 effective purpose: as a perfect revenue hedge for regulated utilities. In this
4 regard, it is even better than other forms of revenue neutrality since there are no
5 true-up provisions, caps, or adjustment factors. The Company is allowed to
6 collect its exact allowed revenues each and every month of the year which
7 eliminates risk including cash flow issues created by seasonality.

8 **Q ARE YOU SAYING THAT THE UTILITY SHOULDN'T BE ALLOWED TO**
9 **EARN ITS ALLOWED REVENUES?**

10 A No. The fact that the utility exactly recovers its allowed revenues until its
11 next rate case is not the problem. The issue is that a very large portion of the
12 risk associated with recovering those revenues has been shifted entirely onto
13 ratepayers without any corresponding benefit. If this proposal is, in fact, a good
14 thing for the Company, then some type of benefit should be passed long to its
15 customers for absorbing this risk.

16 **Q WHAT POTENTIAL INEFFICIENCIES CAN ARISE FROM A SFV RATE**
17 **DESIGN?**

18 A Utilities, while regulated, are similar to other competitive firms in their
19 goals of maximizing profits. These profits are a function of revenues and costs,
20 both of which can reflect a certain degree of uncertainty. However, of the two,
21 revenues can be more uncertain since, as noted earlier, they can be impacted by
22 a wide range of factors beyond a utility's control like change in commodity prices,

1 changes in the economy, and changes in the weather, to name a few. Costs
2 normally have more certainty and are typically within a utility's control.

3 **Q. HOW DOES THE TRADITIONAL RATEMAKING PROCESS GIVE**
4 **UTILITIES INCENTIVES TO REDUCE COSTS?**

5 A. The regulatory lag inherent in the traditional ratemaking process gives
6 utilities strong incentives to reduce costs, and potentially increase earnings,
7 during periods between rate cases. In many instances, this will require effective
8 efforts at reducing costs since, as noted earlier, revenues are much more
9 uncertain. Active cost reducing efforts have the ability to compensate for
10 unknown changes (decreases) in revenues, thereby increasing profitability.
11 However, under a SFV rate design, one-half of this equation, revenues is now
12 known. SFV eliminates revenue uncertainty (assuming a constant level of
13 customers), which in turn can dampen efficiency incentives.

14 **Q DO YOU AGREE THAT REGULATORY COSTS WILL BE REDUCED**
15 **BY THE SFV?**

16 A No, the Company has stated that its proposed SFV will result in a reduced
17 need for repeated rate cases if adopted.⁷ However, the Company has provided
18 no evidence quantifying the reduction in regulatory costs that would result from
19 fewer rate cases, nor have they offered to share any of these benefits with
20 ratepayers. Further, the Company has provided no guarantee that it will not
21 appear before the Commission for another rate case, for some fixed period of
22 time, like 5 years, for instance.

⁷ Amended Direct Testimony of Annette Gardiner, P.E., 27:15-19.

1 **Q DO YOU BELIEVE THAT “SOUND ECONOMIC PRINCIPLES”**
2 **CLEARLY SUPPORT THE USE OF A SFV RATE DESIGN?**

3 A No, and the argument of assigning “fixed costs to fixed charges” is not one
4 that is new in utility regulation. It is also one that has been rejected by regulatory
5 commissions on a number of occasions. The argument tends to be based upon
6 an exclusive consideration of the peak nature of utility systems, when these
7 systems are typically utilized on a mixed, as opposed to exclusively peak use
8 basis. As a result, it has been historic policy practice to have rates that reflect
9 these mixed uses through a combination of fixed and variable charges. It has
10 also been a relatively standard regulatory policy with most states to develop rates
11 that are balanced, change gradually, and encourage conservation. The SFV has
12 none of these attributes.

13 **Q THAT WOULD SEEM TO SUGGEST THAT PRIOR RATE DESIGN**
14 **PRACTICES THAT INCLUDE BOTH FIXED AND VARIABLE CHARGES**
15 **ACTUALLY SERVE A POLICY PURPOSE?**

16 A Yes, and contrary to the Company’s assertion, these rate design practices
17 are not based upon inertia (because it “has always been done that way⁸”), but
18 upon rather sound public policy principles. The Company is also wrong when it
19 asserts that “there is no good reason to design rates this way.⁹” In fact, there are
20 a number of very good, and frequently recognized reasons for designing rates
21 this way: because they result in fair, just, and reasonable rates. The proposed
22 SFV does not.

⁸Amended Direct Testimony of Malcolm R. Ketchum, 22:22-23.

⁹*Ibid.*

1 **Q WHAT DO SOUND ECONOMIC PRINCIPLES HAVE TO SAY ABOUT**
2 **REGULATED FIRMS?**

3 A Generally, sound economic principles, as they are applied to regulated
4 firms, tend to focus more on the appropriate level of cost recovery in the face of
5 economies of scale and less to do with the allocation of charges between fixed
6 and variable costs. In fact, perfect efficiency is typically accepted as being non-
7 attainable in markets facing these types of cost characteristics and the
8 informational problems associated with assigning fixed and common costs.
9 Rather, issues about the recovery of costs between fixed and variable charges
10 tends to be a topic more associated with price discrimination than economic
11 efficiency.

12 **Q WHAT IS PRICE DISCRIMINATION?**

13 A The goals of price discrimination are to develop pricing approaches that
14 maximize profits. Price discrimination can be thought of as charging different
15 customers, different prices for the same service. An example would be the
16 application of senior citizen discounts for meals or movie tickets, or bulk
17 discounts for many items that are purchased at typical warehouse-types stores
18 like Sam's Club. The goals in price discrimination are to segment customers and
19 charge the highest price possible.

20 **Q HOW DOES PRICE DISCRIMINATION RELATE TO RAMSEY**
21 **PRICING?**

22 A Ramsey Pricing is a special case of price discrimination that has been
23 debated in utility regulation for many decades. The goals of Ramsey pricing in

1 utility ratemaking are typically to assign a larger share of a utility's fixed cost, or a
2 larger share of a proposed rate increase, to customers with lower (absolute) price
3 elasticities of demand. In the case of a rate increase, this approach will result in
4 assigning the bulk of the change to small captive customer classes like
5 residential customers, and smaller rate increases to larger customer classes like
6 industrials. The logic of this proposed approach is that it will result in greater
7 profitability since low-price elasticity customers are less like to change their
8 consumption patterns from a rate increase relative to larger customers that have
9 the ability to seek out alternatives, which in the case of the natural gas industry
10 could include fuel switching or direct bypass.

11 **Q HOW DOES THIS RELATE TO THE COMPANY'S SFV PROPOSAL?**

12 A By being restricted exclusively to residential customers, the Company's
13 SFV proposal has Ramsey pricing characteristics in the sense that it assigns a
14 large share of future revenue recovery risk to residential customers and allows
15 larger customer classes off the hook. If the SFV is genuinely based upon "sound
16 economic principles" then fixed costs are fixed costs, and as a consequence,
17 should be applied to all customers equally based upon these principles.

18 **Q HOW IS THE SFV INEQUITABLE?**

19 A It is inequitable in at least three ways. First, as noted several times
20 throughout my testimony, the SFV proposal will shift revenue recovery risk away
21 from the Company and towards residential customers with virtually no benefit.
22 Second, the SFV proposal, as just noted, will shift revenue recovery risk
23 disproportionately upon residential customers and away from larger customer

1 class. Third, it will increase the minimum use charge to customers who tend to
2 be in the most economically disadvantaged position. Exhibit AG-7 shows the
3 changes in bills that will be paid by customers who utilized a typical minimum use
4 level. The distribution service cost portion of these bills, for these customers that
5 have relatively minimal usage would increase by 19 percent. Low income
6 customers would see increases of 20 percent. These are certainly levels of
7 increase that can't be welcome by most households.

8 **Q THE COMPANY NOTES THAT RESIDENTIAL CUSTOMERS WILL**
9 **RECEIVE SEVERAL BENEFITS FROM THE SFV. DO YOU AGREE?**

10 A No. The Company states that customers will get two benefits from the
11 SFV proposal: (1) it is easy to understand; and (2) rates will be less variable.¹⁰
12 These are truisms, not benefits. Clearly a flat rate is easy to understand because
13 there are no other distribution charges to try to understand, and since these
14 charges are fixed by definition, they certainly can't be variable. Even if these
15 were legitimate benefits, they certainly don't stand up as being comparable in
16 magnitude, nor offsetting, to the large reduction in risk that the Company's SFV
17 proposal offers to its shareholders.

18 **Q ARE SFV RATE DESIGNS TYPICALLY SUPPORTED BY ENERGY**
19 **EFFICIENCY ADVOCATES?**

20 A No and while energy efficiency advocates strongly support revenue
21 neutrality, they are equally strong opponents of fixed rate designs like the SFV.
22 These advocates often note that SFV does nothing to encourage energy
23 efficiency since customers are sent signals to use as much as they possibly can

¹⁰Amended Direct Testimony of Malcolm R. Ketchum. 37:3-5; and 37-38:21-1.]

1 for one charge (holding other factors constant). From a non-gas distribution
2 charge perspective, it's like going to a buffet: all you can eat for one price, and as
3 most everyone can attest, buffets are usually not the place where you find people
4 attempting to minimize their caloric intake.

5 **Q WHAT DOES THIS MEAN RELATIVE TO THE COMPANY'S SFV**
6 **PROPOSAL?**

7 A The justifications of a SFV as a energy efficiency rate design should be
8 dismissed. This is not a rate design that is strongly supported by customer
9 groups for promoting efficiency, it's not one that is enthusiastically supported by
10 energy efficiency advocates, and as I will explain in greater detail in a following
11 section of my testimony, it's not one that has been strongly supported by
12 regulatory commissions around the U.S. to promote energy efficiency.

13 **VII STATE REGULATORY DECISIONS ON REVENUE NEUTRALITY**

14 **Q WHICH STATES HAVE ADOPTED REVENUE DECOUPLING?**

15 A Few states have actually adopted revenue decoupling. Exhibit AG-8
16 highlights the states that have energy efficiency programs and their status on
17 decoupling. Exhibit AG-9 shows the states that have addressed SFV. Both
18 Exhibits show states that are actively considering either policy proposal. The
19 exhibits also show those states that have actively rejected or discontinued
20 revenue decoupling or SFV. As seen from the Exhibit AG-8, there are just as
21 many states that have rejected or discontinued revenue neutrality programs as
22 there are those who have adopted any of these policies. The same holds true for
23 Exhibit AG-9.

1 **Q HAVE ANY STATES REJECTED REVENUE DECOUPLING?**

2 A. Yes. As seen from Exhibit AG-8, there are a number of state regulatory
3 commissions that have reviewed and rejected revenue decoupling as a policy
4 mechanism for promoting DSM. Connecticut, Arizona, Arkansas, and
5 Washington are among those states that have expressed concerns or serious
6 reservations about the use of revenue decoupling as a regulatory policy tool and
7 rejected its proposed implementation.

8 **Q. WOULD YOU PLEASE DISCUSS THE CONNECTICUT FINDINGS**
9 **REGARDING REVENUE DECOUPLING?**

10 A. The Connecticut Department of Public Utility Control ("DPUC") recently
11 ruled against revenue decoupling for its electric and gas utilities. The DPUC
12 ruled that the state's utilities are "performing well and that incentives available to
13 the companies and their customers provide good incentives to promote
14 conservation and load management."¹¹ Thus, as noted earlier, the DPUC seems
15 to believe that the traditional regulatory framework provides appropriate
16 incentives for utilities to provide least-cost service, regardless of whether the
17 resources acquired are supply- or demand-oriented.

18 **Q. CAN CONNECTICUT UTILITIES GET LOST REVENUES ASSOCIATED**
19 **WITH DSM?**

20 A. Only in limited situations where the utility shows that lost revenues due to
21 conservation resulted in achieved earnings below their allowed rate of return. In
22 addition, the DPUC took issue with: (1) the position that decoupling creates

¹¹ Investigation into Decoupling Energy Distribution Company Earnings from Sales, Decision, Connecticut Department of Public Utilities, Docket No. 05-05-09, January 18, 2006.

1 incentives for DSM; and (2) the degree to which decoupling shifts business risk
2 from a utility to consumers. The DPUC found that:

3 "...decoupling by itself does not provide an incentive to energy DCs
4 to promote conservation. Rather, in helping to ensure fixed cost
5 recovery, it removes a disincentive for companies to promote
6 conservation. However, it may also shift to ratepayers such normal
7 business risks as lower sales due to economic downturns, weather,
8 new energy efficiency technology, and demand response to price
9 increases. This report discusses mechanisms for various degrees
10 of decoupling ranging from partial to full decoupling. In general,
11 the more complete the decoupling, the more business risks
12 are shifted from the energy DCs to the ratepayers."¹²

13 **Q WHAT ABOUT THE ARIZONA FINDINGS REGARDING REVENUE**
14 **DECOUPLING?**

15 A The Arizona Corporation Commission ("ACC") addressed a number of
16 issues comparable to those raised in this case. Of particular relevance to the
17 SFV proposal at hand, were the claims made in the Arizona proceeding about
18 revenue decoupling and recent declines in average use per customer. The ACC
19 found, similar to the guiding principles I discussed earlier, that:

20 "[t]here is conflicting evidence in the record as to whether the
21 recent level of declining per customer usage will continue into the
22 foreseeable future, and whether conservation efforts are the direct
23 cause of Southwest Gas' inability to earn its authorized return from
24 such customers."¹³

25 The Commission added:

26 "[t]he Company is requesting that customers provide a guaranteed
27 method of recovering authorized revenues, thereby virtually

¹² Ibid, *emphasis added*.

¹³ In the Matter of the Application of Southwest Gas Corporation for Establishment of Just and Reasonable Rate and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of the Properties of Southwest Gas Corporation Devoted to its Operations Throughout the State of Arizona, Arizona Corporation Commission, Docket No. G-01551A-04-0876; Decision No. 68487, February 23, 2006.

1 eliminating the Company's attendant risk. Neither the law nor
2 sound public policy requires such a result."¹⁴

3 **Q. HOW DID THE WASHINGTON COMMISSION RECENTLY RULE ON**
4 **REVENUE DECOUPLING?**

5 A. Yes. The Washington Utilities and Transportation Commission ("WUTC")
6 recently rejected a joint decoupling proposal offered by PacifiCorp and the
7 Natural Resources Defense Council ("NRDC"), an environmental advocacy
8 group. The WUTC, while being open to the idea of revenue decoupling, found
9 several problems with PacifiCorp's proposal. Namely, that the proposal was not
10 well-founded, documented, and did not have firm commitments for explicit DSM
11 programs. The WUTC ruled:

12 "We favor utility efforts that accomplish cost-effective conservation
13 through reducing utility costs and allowing consumers to manage
14 their bills. A well-designed decoupling mechanism may support the
15 Company's increased investment in energy conservation and
16 promote our state's goal of furthering energy conservation. We
17 must reject the specific joint proposal offered by the Company and
18 NRDC, however, for the following reasons: 1) We cannot calculate
19 the mechanism's fixed cost revenue requirement without first
20 having adopted an allocation methodology sufficient to make rates;
21 2) The proposal lacks important analysis of implementation costs
22 and its impact on the Company's overall revenues and cost of
23 equity, and; 3) The Company has failed to identify and commit to
24 incremental conservation measures as a counterbalance to its
25 potential reduction in risk. We expect the Company to provide such
26 evidence to allow us to fully consider a decoupling proposal."¹⁵

27 **Q WHAT HAS BEEN THE RECENT EXPERIENCE WITH SFV**
28 **PROPOSALS AROUND THE COUNTRY?**

¹⁴ Ibid

¹⁵ Washington Utilities and Transportation Commission, Complainant, v. PacifiCorp d/b/a Pacific Power & Light Company, Respondent in the Matter of the Petition of PacifiCorp d/b/a Pacific Power & Light Company for an Order Approving Deferral of Costs Related to Declining Hydro Generation, Docket UE-050684; Order 04; Docket UE-050412; Order 03, Washington Utilities and Transportation Commission, April 17, 2006, Dated.

1 A Generally, SFV appears to be a somewhat less favorable rate design
2 proposal than revenue decoupling for many LDCs. As noted by the Company,
3 there is one well-cited example of complete SFV adoption – in Georgia for
4 Atlanta Gas Light (“AGL”). However, this proposal was adopted following
5 legislative direction, not a Commission ruling. A number of other utilities have
6 proposed similar, or modified mechanism in their respective states. In some
7 instances, like North Dakota, the SFV rate design was accepted. In some
8 instances, the proposals have been openly rejected such as in Arkansas and
9 Arizona. Many other states have rejected complete SFV, but have allowed some
10 gradual increases in basic customer charges. These states would include
11 Florida, Nevada, and Washington. Overall it appears that, of the states
12 considering complete SFV, more have rejected it than adopted it.

13 **Q WHAT HAS BEEN THE RATIONALE FOR THOSE STATES THAT**
14 **HAVE COMPLETELY REJECTED SFV?**

15 A The primary rationales for outright rejection of SFV have usually been
16 based upon the findings that a SFV shifts revenue recovery risk to ratepayers, it
17 is inequitable, and does nothing to encourage energy efficiency. For instance,
18 the Arkansas Commission, in considering a voluntary fixed pricing proposal
19 offered by CenterPoint Energy Arkla, noted that the plan would add complexity to
20 the gas supply rate and cause more billing accounting problems. In addition, it
21 could potentially lead to the potential for cross-subsidization and cost shifting to

1 customers who did not elect to take the Voluntary Fixed Price Option ("VFPO").¹⁶
2 The Arkansas Commission also rejected a revenue decoupling plan in the same
3 proceeding based upon the justification that it would represent considerable risk-
4 shifting away from the utility and its shareholders and towards ratepayers.¹⁷

5 **Q HOW DID THE ARIZONA COMMISSION RULE ON THE PROPOSED**
6 **SFV OFFERED BY SOUTHWEST GAS?**

7 A While not directly proposing a SFV, Southwest Gas did propose to
8 dramatically increase its customer charges based upon some of the same "cost-
9 based" principles advocated by SEMCO in this proceeding. The Commission
10 was very concerned about the large increase in the customer charge that would
11 have resulted from the proposal, as well as the implications that this type of rate
12 design would have for energy efficiency. The Commission noted that:

13 "...it is simply untenable to saddle a substantial number of the
14 Company's residential customers with rate increases in excess of
15 100 percent. Under the Company's recommendation, low usage
16 residential customers would incur not only a doubling of their basic
17 monthly charge....the rate design would [also] have the effect of
18 encouraging greater usage of natural gas at a time when, by all
19 accounts, an increase in demand for natural gas is coupled with
20 shortages in supply. We do not believe that it is appropriate to
21 send a signal to customers of "the more you use, the more you
22 save."¹⁸

¹⁶ In the Matter of an Application for a General Change or Modification in Centerpoint Energy Arkla, a Division of Centerpoint Energy Resources Corp's Rates, Charges and Tariffs, Docket No. 04-121-U; Order No. 16, Arkansas Public Service Commission, September 19, 2005.

¹⁷ Ibid

¹⁸ In the Matter of the Application of Southwest Gas Corporation for Establishment of Just and Reasonable Rate and Charges Designed to Realize a Reasonable Rate of Return on the Fair Value of the Properties of Southwest Gas Corporation Devoted to its Operations Throughout the State of Arizona, Arizona Corporation Commission, Docket No. G-01551A-04-0876; Decision No. 68487, February 23, 2006.

1 The Arizona Commission drew a conclusion that should be appropriate in the
2 consideration of the rate design proposals being offered in this proceeding when
3 it noted that:

4 ...we agree with all parties that movement closer to cost-based
5 rates is in principle a laudable goal. However, that goal must be
6 balanced with consideration of the principles of gradualism,
7 fairness, and encouragement of conservation.”¹⁹

8 **Q CAN YOU EXPLAIN THE CONCLUSIONS REACHED BY THOSE**
9 **STATES THAT HAVE ALLOWED SOME GRADUAL INCREASES IN**
10 **CUSTOMER CHARGES?**

11 A These states offered rulings that balance the goals of a movement to more
12 cost-based rates with the issues of fairness, equity, and energy efficiency. For
13 instance, Central Florida Gas proposed a SFV to the Florida Commission on the
14 justification that it would move rates closer towards costs. Central Florida Gas
15 argued that since it had exited the merchant function, a movement to SFV was
16 more appropriate. The Florida Commission expressed concern at the overall
17 nature of the Company’s proposed rate design and the fact that the proposals
18 “would provide little opportunity [for customers] to lower their bills through
19 decreases in gas usage.”²⁰ The Florida Commission was also concerned about
20 intra-class equity issues since customers that used very little could find
21 themselves paying the same distribution charges as those customers using a

¹⁹ Ibid

²⁰ In re: Petition for authorization to establish new customer classifications and restructure rates, and for approval of proposed revised tariff sheets by Florida Division of Chesapeake Utilities Corporation, Docket No. 040956-GU; Order No. PSC-05-0208-PAA-GU, Florida Public Service Commission, February 22, 2005, Issued.

1 considerable amount of natural gas. The Florida Commission ultimately rejected
2 the proposed SFV, but did allow some increases in basic service rates.

3 **Q WHAT WERE SOME OF THE OTHER STATE FINDINGS ON RECENT**
4 **RATE DESIGNS BEING PROPOSED ON “SOUND ECONOMIC**
5 **PRINCIPLES?”**

6 A While Southwest Gas did not promote a full SFV rate design in 2004, it did
7 attempt to increase its customer charges to a relatively large level. SW Gas
8 promoted this rate design because it believed it was more consistent with cost-
9 based principles. The Nevada Commission rejected the large increase in favor
10 of a much more limited increase that reflected a more gradual approach in
11 customer charge changes.²¹ A more gradual approach has also been agreed to
12 in a settlement recently filed in Washington. Cascade Gas has agreed to keep
13 the customer charge the same for residential customers, and only increase the
14 charge for larger customer classes.²² Thus, there are relatively strong examples
15 around the country that support a balancing approach in setting rates. This has
16 been true in states that have reviewed rate design proposals that are even less
17 extreme than the Company's.

18 **Q WHAT WERE THE TERMS AND CONDITIONS UNDER WHICH MOST**
19 **STATE COMMISSIONS AND UTILITIES ADOPTED OR CONSIDERED**
20 **REVENUE NEUTRALITY?**

²¹ Application of Southwest Gas Corporation for authorization to increase its rates and charges, including revised depreciation rates, and changes in other tariff provisions for its Southern and Northern Divisions, Docket No. 04-3011, Nevada Public Service Commission, August 26, 2004

²² Washington Utilities and Transportation Commission, Complainant, v. Cascade Natural Gas Corporation, Respondent, Docket No. UG-060256, Settlement Agreement, filed October 11, 2006.

1 A. Most all of the Commissions granting revenue neutrality mechanisms,
2 especially revenue decoupling, were those where the utility: (1) had prior DSM
3 experience; and/or (2) were making some additional level of commitment to
4 expand their DSM initiatives.

5 **Q HOW MANY OF THESE DECOUPLED UTILITIES HAD PRIOR**
6 **EXPERIENCE WITH DSM?**

7 A Several decoupled utilities had prior DSM experience. For instance, NW
8 Natural has had DSM programs in place for a decade and, over the past 8 years,
9 has defined their DSM strategies as part of their IRP. In California, natural gas
10 utility energy efficiency programs are required by statute.²³ In addition,
11 Southwest Gas Company ("SWG") had experience with DSM in both Arizona and
12 Nevada. And, while Baltimore Gas & Electric ("BG&E") and Washington Gas
13 Light ("WGL") may not have had DSM plans in place for natural gas, BGE had
14 extensive experience in DSM on the electric side of their operations.

15 **Q. HOW DOES THIS RELATE TO THE CURRENT SFV PROPOSAL?**

16 A. Even if the Commission were to accept SFV as a rate design that
17 promoted energy efficiency, the Company's request to have the Commission
18 adopt a revenue neutrality program based upon energy efficiency grounds is
19 premature and is inconsistent with practices in most other states. Those states
20 generally adopted revenue neutrality when its gas utilities had experience with
21 DSM and were asking to expand their initiatives beyond current levels. Further,
22 these utilities were offering relatively solid DSM proposals that were in keeping

²³ Order Instituting Rulemaking to Examine the Commission's Future Energy Efficiency Policies, Administration and Programs, Decision 03-12-060; Rulemaking 01-08-028, California Public Utilities Commission, August 23, 2001, Filed; December 18, 2003, Dated.

1 with their Commission's prior practices as well as those followed in the industry.
2 SEMCO does not have a long track record with DSM programs, has no active
3 programs at this time, and, as will be discussed later in my testimony, has
4 provided a DSM plan that has no documented savings estimates and no findings
5 of overall program cost-effectiveness. Most importantly, the Company can
6 provide no quantitative evidence that the promotion of its proposed DSM plan will
7 create lost revenues or any financial harm. While SEMCO may argue for
8 adopting SFV on a variety of other grounds, there appears to be very little
9 substantive evidence that adopting SFV to support energy efficiency has any
10 merit. And as I will note later, this DSM plan is very weak relative to standard
11 industry practices and is not an appropriate concession or benefit in return for the
12 dramatic shift in risk that the SFV poses.

13 **Q. IN LOOKING AT OTHER GAS UTILITIES, IS IT THE CASE THAT**
14 **REVENUE NEUTRALITY IS NEEDED IN ORDER TO BE SUCCESSFUL AT**
15 **PROMOTING DSM?**

16 A. No, that does not appear to be the case. Exhibit AG-10 is a modified
17 version of a table originally prepared by the Southwest Energy Efficiency Project
18 examining DSM programs, costs, and savings for 2004. Of the 10 listed, only
19 three have revenue decoupling. Interestingly enough, the top 2 gas utilities on
20 the list in terms of total program spending as a percent of retail revenues
21 (Vermont Gas and Aquila) do not have revenue decoupling and yet outspend, as
22 a share of revenues, the three utilities that have revenue decoupling. In terms of

1 performance, Vermont Gas and Keyspan were able to attain benefit-cost ratios of
2 5.6 and 3.0, respectively, without any type of revenue decoupling program.

3 **VIII EXAMINATION OF THE COMPANY'S DSM PROPOSALS**

4 **Q WOULD YOU PLEASE DISCUSS THE COMPANY'S DSM PROPOSAL?**

5 A Yes. The Company has proposed to initiate a DSM plan in return for
6 being allowed to modify its rate design to a SFV format. The program, creatively
7 referred to as "This Cold House," is comprised of six main components: (1)
8 education; (2) analysis; (3) measures; (4) tracking; (5) financing; and (6) LIEEF
9 funding. The Company has requested an annual \$2.0 million expense to be
10 recovered in rates to cover the costs of the overall energy efficiency program.
11 These program costs have been provided by program in Exhibit A-12, Schedule
12 1.

13 **Q WOULD YOU PLEASE DESCRIBE THE FIRST COMPONENT OF THE**
14 **COMPANY'S OVERALL DSM PROGRAM?**

15 A The first component of the Company's proposed DSM program is
16 associated with consumer education. This program has a number of sub-
17 components that includes:

- 18 (1) Discussing energy efficiency in its bill inserts referred to as
19 *Connectivity*;
20 (2) A newspaper and mass media campaign;
21 (3) Creating a number of customer forums;
22 (4) Creating an information exhibit;
23 (5) Speakers bureau; and

1 (6) The development of two videos for its web-site.

2 **Q ARE THERE ANY PROBLEMS WITH THIS PROGRAM?**

3 A Yes, this program is poorly documented and fails to provide any
4 quantitative evidence regarding the degree to which customers will benefit from
5 the program. For instance, while the Company notes that "customer education
6 has the potential to be the single largest contributor to conservation across all
7 customer segments," it provides no quantitative evidence to support this
8 conclusion.²⁴ While consumer education programs are generally accepted to
9 have the opportunity to create household savings, the Company has conducted
10 no specific analysis, nor provided any specific estimates, regarding the total gas
11 savings (in total Dth saved) for its Michigan customers.

12 **Q IS THE COMPANY CURRENT CONDUCTING ANY OF THESE**
13 **PROPOSED EDUCATIONAL MEASURES?**

14 A Yes. The Company publishes, on average, six *Connectivity* bill inserts per
15 year.²⁵ Over the last three years, they have dedicated 15 out of 20 of these bill
16 inserts to conservation and energy efficiency topics.²⁶ The Response to the
17 Attorney General's Third Discovery Request to SEMCO Energy Gas Company 3-
18 AG-98 includes some of the inserts that have been issued over the past 36
19 months that have addressed energy efficiency topics. This response clearly
20 shows that the Company has already been addressing energy efficiency in its

²⁴ Company Application, Exhibit A-12, Schedule 1, p. 3; Response to Attorney General's Second Discovery Request to SEMCO Energy Gas Company, 2-AG-75; and Response to Attorney General's Third Discovery Request to SEMCO Energy Gas Company 3-AG-97.

²⁵ Company Application, Exhibit A-12, Schedule 1, p. 4.

²⁶ Response to Attorney General's Third Discovery Request to SEMCO Energy Gas Company, 3-AG-98.

1 newsletters on a regular basis. Yet the Company would like the Commission to
2 allow it to collect an additional \$60,000 in rates for activities which they are
3 already conducting (for a level of effort lower than currently being conducted).

4 **Q DO YOU HAVE ANY PROBLEMS WITH SOME OF THE OTHER**
5 **EDUCATIONAL PROPOSALS?**

6 A Yes. Many of these proposals, like enhancing the Company's web-site, or
7 creating a speakers bureaus ought to be activities the Company does as a
8 normal course of business. Having Company representatives talk with the
9 media, participate in workshops with educational institutions, local and/or state
10 governmental agencies, or non-profit groups on energy efficiency should be a
11 standard part of the Company's communication process. In addition, it is not
12 clear why creating five different two- to three-minute videos would be more
13 helpful than just creating a number of web-links to the hundreds of sites on the
14 internet that provide information on how to save energy. Since the Company has
15 provided no estimate of the energy savings benefits for these proposals, nor
16 have they shown why certain proposals result in more effective energy savings
17 opportunities than others, the entire cost of this program should be excluded from
18 the Company's proposed revenue requirement. The Commission should also
19 reject these proposals since there is no documentation about what will be
20 included in these educational plans, whether any successful educational plans
21 utilized in other states will be adopted as templates for SEMCO's Michigan
22 operations, nor are there any proposed input nor accountability processes for

1 educational materials through any kind of stakeholder process or Commission
2 oversight.

3 **Q HAS THE COMPANY PROVIDED ANY ESTIMATES OF THE**
4 **POTENTIAL LOST REVENUES OR MARGINS THAT WOULD RESULT FROM**
5 **THIS PROGRAM?**

6 A No, in addition to not being able to quantify the savings associated with
7 this program, the Company has been unable to provide any estimates of how
8 promoting such programs would result in lost revenues or any financial harm.²⁷

9 As such, there is no proof that promoting educational programs, as a normal
10 course of business operations and communications with the public, will result in
11 lower profitability. The fact that the Company already conducts such activities,
12 without having the modifications included in their proposed SFV rate design,
13 suggests that there are no financial disadvantages from providing the public with
14 useful information on how to reduce their bills and increase the efficiency of their
15 natural gas usage.

16 **Q WHAT HAVE THE PARTICIPATION LEVELS FOR THE COMPANY'S**
17 **EDUCATION PROGRAMS BEEN BASED UPON?**

18 A No participation levels have been estimated for this program. The
19 Company has provided some activity levels, which represents the effort that they
20 are proposing to put into the program, but the number of customers and potential
21 savings that will result from this program have not been defined. Further, the
22 Company's own activity levels appear to have been based upon a rather

²⁷ Response to Attorney General's Third Discovery Request to SEMCO Energy Gas Company, 3-AG-98.

1 subjective determination of what the Company believes to be an appropriate
2 level of effort in disseminating information about energy efficiency. However,
3 most of the programs being offered by the Company are “passive” in nature and
4 it is not clear how end-users will directly benefit from such efforts.

5 **Q LET’S TURN TO THE SECOND PROGRAM. CAN YOU PLEASE**
6 **DISCUSS THE COMPANY’S ANALYSIS PROPOSAL?**

7 A Yes. The Analysis portion of the Company’s DSM program would provide
8 customers with specific information about energy efficiency opportunities. This
9 program is similar to the educational program in the sense that the Company is
10 not directly performing, or coordinating, any specific DSM measures or programs.
11 In other words, the program is relatively “passive” and requires customers to both
12 seek out energy efficiency information and to expend the effort to create their
13 own energy efficiency opportunities. The Analysis Program consists primarily of
14 the Company serving in a “brokering” role to disseminate information about other
15 companies and contractors that actually provide energy efficient services and
16 goods. The components of this portion of the program includes: (1) providing a
17 “do-it-yourself” energy audit kit; and (2) providing, defining, and maintaining a
18 listing of trained professionals that conduct home audits.

19 **Q DO YOU HAVE ANY PROBLEMS WITH THIS PROPOSAL?**

20 A Yes, there are number of problems associated with the Analysis program.
21 First, this program has been developed in a fashion that is entirely inconsistent
22 with traditional DSM practices. Savings levels and goals have not been defined,
23 program costs are developed in the most general terms, customer-specific

1 saving levels are not estimated, participation levels are somewhat arbitrary, and
2 most importantly, no analysis of the cost-effectiveness of these programs has
3 been provided. The Commission should reject any DSM program, regardless of
4 how meritorious the effort, that is not based upon a quantitative finding that the
5 benefits outweigh the costs. This has been common practice in Michigan, as well
6 as most all other regulatory commissions around the U.S.

7 **Q ARE THERE ANY SPECIAL ACCOUNTABILITY ISSUES THE**
8 **COMMISSION SHOULD CONSIDER IN EXAMINING THE COMPANY'S DSM**
9 **PROPOSALS?**

10 A Yes, the Commission should set the Company to a very high standard in
11 terms of the overall level of energy efficiency being proposed in this proceeding.
12 It should also hold the Company to a very high level of accountability, in terms of
13 potential DSM savings, goals, and documentation. The Company is asking for a
14 very extreme rate design proposal: one that is rarely used in rate regulation
15 around the U.S. The benefits to the Company, and its shareholders, are very
16 clear. What is not clear, and what has not been clearly provided by the
17 Company, are the reciprocal benefits being offered to ratepayers in return for the
18 significant shifting of risk.

19 **Q HOW WERE THE COST ESTIMATES FOR THE ANALYSIS PART OF**
20 **THE DSM PROGRAM DEVELOPED?**

21 A The cost estimates were developed in the most general terms. For
22 instance, the Company notes that:

23 "The cost estimate used fell within the range of total costs that the
24 Company believes are required to develop and maintain an

1 effective energy analysis program. The conservation program was
2 developed as a menu of options. The options and costs approved
3 by MPSC order will determine the amounts spent on individual
4 options.”

5 and

6 “The cost estimate used fell within the range of total costs that the
7 Company believes are required to conduct a professional energy
8 audit. The conservation program was developed as a menu of
9 options. The options and costs approved by MPSC order will
10 determine the amounts spent on individual options.”²⁸

11 **Q HOW WERE CUSTOMER SAVINGS ESTIMATES DEVELOPED?**

12 A The Company has provided no customer savings estimates associated
13 with this program.²⁹ As a result, there is no way of determining whether there are
14 any public benefits from adopting these proposals in the sense that there is a
15 clear finding that the benefits, in Dth savings created, outweigh the costs
16 associated with program development and implementation.

17 **Q DID THE COMPANY ESTIMATE ANY LOST REVENUES FROM THIS**
18 **PORTION OF THEIR DSM PROGRAM?**

19 A No the Company indicated that “[t]his type of analysis is not part of the
20 proposed conservation program.”³⁰ The Commission should reject the
21 Company’s claims about financial harm resulting from energy efficiency since the
22 Company cannot provide any significant evidence to that effect.

23 **Q WHAT ABOUT THE COMPANY’S THIRD PROGRAM? CAN YOU**
24 **EXPLAIN THE “MEASURES” PROPOSAL?**

²⁸ Response to Attorney General’s Third Discovery Request to SEMCO Energy Gas Company, 3-AG-99.

²⁹ Ibid

³⁰ Ibid

1 A The measure proposal is the closest set of energy efficiency proposals
2 offered by the Company that are even comparable with standard utility practices.
3 Under this approach, the Company is proposing to offer a number of different
4 energy efficiency measures that it will directly support. These include an
5 appliance program and an envelope program. Under the appliance program, the
6 Company will promote the use of high efficiency furnaces by offering a \$200
7 rebate to customers that select a 90 percent AFUE furnace. It will also provide a
8 water heating wrap program in addition to some very generalized statements
9 about promoting high efficiency water heaters. The envelope measures include
10 the promotion of: caulking, weather stripping and window covering; automatic
11 setback thermostats; back-draft dampers; vent dampers; insulation; high
12 efficiency windows; and some unidentified approach at reducing water
13 consumption, which at \$30 to \$50 per application, could presumably include
14 some type of relatively expensive low-flow showerhead.

15 **Q DOES THIS PROPOSAL INCLUDE RELATIVELY DETAILED COST**
16 **AND GAS SAVINGS ESTIMATES?**

17 A No. The Company has based its estimates on "an assumption that the
18 Company would provide a \$200 rebate to customers who select a 90% AFUE
19 Furnace as stated in the Conservation Plan." The cost for "all of the other items
20 were developed by investigating the cost of these items at local improvement
21 outlets and vendors supplying these types of products and services." In addition,
22 the "proposed \$200 rebate was determined by reviewing other high efficiency
23 furnace programs referenced in a report issued by the American Council for an

1 Energy-Efficient Economy, Examining the Potential for Energy Efficiency to help
2 address the Natural Gas Crisis in the Midwest. Various programs were described
3 in the report, but in most cases, a financial incentive for installing higher
4 efficiency equipment was integral to the success of the plan.”³¹

5 **Q WOULD YOU PLEASE DISCUSS THE COMPANY’S TRACKING**
6 **PROGRAM?**

7 A Yes. This is perhaps one of the most undocumented proposals in the
8 Company’s entire DSM program. The program is being proposed in order to
9 provide information to customers that will allow them to track and analyze their
10 consumption before and after energy conservation measures are adopted.
11 Exactly what changes in billing software being needed to make this change in the
12 way usage information is communicated to customers has not been provided.
13 The difference in the information being provided to customers, from what is
14 already included on customer bills, is equally ambiguous. For instance, the
15 Company indicated that:

16 “[t]he information currently shown on customer bills indicates the current
17 actual monthly consumption and the actual consumption from the same
18 month from the previous year. This information is represented on the bill
19 in the same type and size as all of the other information on the bill. The
20 Company is proposing to provide, on an annual basis, a document
21 developed for individual users that is easy to read and understand,
22 detailing the individual customer’s weather normalized energy usage and
23 compare that usage to the previous year.”³²

24 **Q HAS THE COMPANY IDENTIFIED ANY BENEFITS WITH THIS**
25 **PROPOSAL?**

³¹ Response to Attorney General's Third Discovery Request to SEMCO Energy Gas Company, 3-AG-100.

³² Response to Attorney General's Third Discovery Request to SEMCO Energy Gas Company, 3-AG-101.

1 A No, the Company has provided no DSM goals for this particular portion of
2 its program, nor has it provided any estimates of the potential savings ratepayers
3 will get for the \$625,000 annual expense that the Company is proposing to
4 include into rates. This is a significant problem for this particular request since,
5 as seen in Exhibit AG-11 the total cost of the program accounts from some 42
6 percent of the entire DSM program. The Commission should reject this request
7 since there is no clear indication of the potential benefits, in terms of Dths saved,
8 for ratepayers.

9 **Q HOW HAVE THE PROGRAM COST ESTIMATED BEEN DEVELOPED?**

10 A The Company has indicated that “[t]he cost estimate created for this
11 efficiency report was developed by dialog with a vendor who currently provides
12 this type of service to other utilities.”³³ No information was provided regarding
13 this vendor quote or the nature of the service being provided. The Company also
14 did not provide any information indicating that it solicited bids from any other
15 vendors to compare the costs of this proposal to ensure that it was the least-cost
16 option available in the market.

17 **Q DO YOU HAVE ANY CONCERNS ABOUT THE PARTICIPATION**
18 **LEVELS?**

19 A Yes. First, the company notes that the purpose of this program is to assist
20 customers in understand how changes in consumption before and after
21 adoption of energy efficiency programs. The Company estimates some
22 250,000 customers participating in this program. However, the highest level of

³³ Response to Attorney General's Third Discovery Request to SEMCO Energy Gas Company, 3-AG-101.

1 DSM participation in the other measures being offered by the Company is only
2 5,000 customers – a number far lower than what the Company anticipates being
3 associated with the tracking program. The only possible explanation for the
4 discrepancy (250,000 to 5,000) is that the Company is including customers that
5 independently adopt energy efficiency measures, which in turn, raises an
6 additional question: on what basis has the Company determined that 250,000 of
7 its customers are actively adopting independent energy efficiency measures? In
8 addition, the tracker program participation level is approximately 113 percent of
9 its 2005 total residential customers. Given this large level it appears that this
10 DSM measure is not going to be voluntary, but mandatory. Further, the
11 Company has designed this program, as well as its program costs, on a level of
12 customers that is some 112 percent higher – or some 26,617 customers, than
13 the Company's proposed test year.

14 **Q DOES THE TRACKER PROGRAM SEEM LIKE A TRADITIONAL DSM**
15 **MEASURE TO YOU?**

16 A No, this plan appears to be a mandatory changing in usage measurement
17 and reporting. The Company cannot offer any estimates of typical savings
18 associated with the plan. The plan is also mandatory and not voluntary which is
19 an approach typically not utilized in DSM program development. As such, it
20 should not be treated as an energy efficiency measure, but part of the
21 Company's overall revenue requirement for providing service to customers. The
22 Commission should reject this proposal since the Company has provided no
23 evidence on the need for the program, has not provided enough information that

1 it represents the least cost option for this particular service, and is based upon a
2 customer level that is well in excess of the test year.

3 **Q WHAT ABOUT THE FINANCING PROGRAM?**

4 A The financing programs appears to be an after thought. The Company
5 currently offers a financing program for qualified dealers and customers who are
6 purchasing furnace or related equipment. However, rather than being oriented to
7 conservation per se, these types of programs are typically developed for fuel
8 switching and load building. The Company has noted that its financing program
9 could be extended to support higher-cost energy conservation measures, but
10 offers no plan for doing so. Thus, the role of Company-sponsored financing, while
11 referenced in the program, is non-existent.

12 **Q CAN YOU DISCUSS THE LAST PROGRAM: THE PROPOSED LIEEF**
13 **FUNDING MECHANISM?**

14 A The Company is requesting that it provide two percent of its commercial
15 and industrial revenues to support low cost energy efficiency through the Low-
16 Income Energy Efficiency Fund ("LIEEF"). This would result in a \$520,563
17 contribution from SEMCO's ratepayers to the total fund. The Company notes
18 that this fund was created by the "Customer Choice and Electric Reliability Act of
19 2000" (2000 PA 141). The fund was primarily developed to support low-income
20 customers and to be funded from dollars collected in excess of securitized levels
21 for utilities facing restructuring. There does not appears to be any provision for
22 expanding this funding to other utilities, or any provisions for dollars not
23 associated with excess securitization being applied to this funding proposal.

1 **Q ARE THERE ANY PROBLEMS WITH THIS PROPOSAL?**

2 A Yes. While supporting low-income customers with bill and energy
3 efficiency is admirable, a policy interpretation of the statutes supporting these
4 provisions does not appear to require all utilities to support the program, only
5 those with excess securitization collections. SEMCO is not required to support
6 this program despite the meritorious purpose of the gesture.

7 **Q EARLIER YOU NOTED THAT MOST ALL ASPECTS OF THE**
8 **COMPANY'S DSM PROPOSAL WERE INCONSISTENT WITH TRADITIONAL**
9 **DSM PRACTICES. CAN YOU PLEASE EXPLAIN THESE PRACTICES IN**
10 **GREATER DETAIL?**

11 A Yes. The Company's proposed energy efficiency plan is very loosely
12 defined, includes little documentation supporting its cost estimates, provides no
13 specific energy savings levels associated with the program, and has generally
14 been developed and offered in a fashion entirely inconsistent with common utility
15 and regulatory practice. This proposal is insufficient for regulatory approval since
16 there is no way of comparing the costs of this energy efficiency proposal to its
17 benefits. In the absence of any specific cost-effectiveness finding, not
18 generalities, such a proposal would need to be dismissed in its entirety. The
19 proposal is even more problematic given the significance of the Company's
20 proposed SFV rate design. The Company is not only asking for rate recovery of
21 a significant amount of expenditures (\$2.0 million per year), it is also asking for
22 an exceptionally dramatic change in the way it collects its revenues from

1 customers. The Company is asking quite a lot from customers, and offering very
2 little of substance in return.

3 **Q HAS THE COMPANY PROVIDED ANY EXPLANATION REGARDING**
4 **WHY ITS PROPOSALS HAVE BEEN PROVIDED IN MANNER THAT IS NOT**
5 **IN KEEPING WITH TRADITIONAL APPROACHES?**

6 A Yes, when asked to identify the estimated savings and costs associated
7 with the proposed energy efficiency plan, the Company indicated that it:

8 "...developed the Customer Efficiency and Conservation Plan as a
9 relatively simple, common sense approach to energy conservation
10 and wishes to avoid extensive administrative and regulatory
11 burdens associated with technical evaluations of various program
12 alternatives."³⁴

13 In a later data request response, the Company again stated:

14 "...developed the Customer Efficiency and Conservation Plan as a
15 relatively simple, common sense approach to energy conservation
16 and wishes to avoid extensive administrative and regulatory
17 burdens associated with technical evaluations of various program
18 alternatives."³⁵

19 **Q HAS THE COMPANY PROVIDED ANY INDICATION AS TO WHY IT**
20 **HAS CHOSEN A "SIMPLE" PLAN?**

21 A There are some relatively cryptic and generally unsupported claims about
22 unfavorable experiences with past DSM programs that were adopted around the
23 U.S. that appears to be the justification for the "simple" approach being offered
24 by the Company. For instance, the Company notes that many utilities were
25 required to include DSM tracking programs in order to measure the recovery of

³⁴ Response to Attorney General's Second Discovery Request to SEMCO Energy Gas Company, 2-AG-75

³⁵ Response to Attorney General's Second Discovery Request to SEMCO Energy Gas Company, 3-AG-97

1 lost revenues at some point in the future. The Company, for instance, cites what
2 it believes to be a cumbersome process for accounting for lost revenues that was
3 required by Detroit Edison in the early 1990s.³⁶

4 **Q DO YOU AGREE WITH THE COMPANY'S CONCLUSIONS?**

5 A No. The Company is confusing two issues: first, the regulatory
6 requirements associated with developing and implementing DSM; and second,
7 the regulatory process required to recover lost revenues. The Company has
8 addressed issues associated with the second problem, lost revenue recovery,
9 and not the first, the regulatory requirements for DSM implementation. If the
10 cumbersome nature of lost revenue recovery is the justification for the proposed
11 DSM program's inherent simplicity, then the benefits are entirely one-sided since
12 they only address the Company's ability to recover lost revenues and do not
13 address any ratepayer benefits by moving to a more simplistic approach. Lastly,
14 the Company has failed to quantify any reduction in regulatory burdens (i.e.,
15 reduced regulatory costs) and failed to share the benefits of these reduced
16 burdens with ratepayers either through lower rates, or an increase in DSM
17 program offerings. Thus, the Commission should reject the entire program as
18 being incomplete and lacking clearly defined benefits for ratepayers.

19 **Q DO YOU AGREE WITH THE ARGUMENTS THAT THE PROPOSAL**
20 **REDUCES REGULATORY BURDENS?**

21 A No and while no one wants unnecessary regulatory burdens, dismissing
22 all standard regulatory practices associated with the development and review of
23 DSM measures is equally undesirable. Allowing the Company to recover the

³⁶ Amended Direct Testimony of Malcolm R. Ketchum, 31-33:14-3.

1 costs associated with this DSM proposal would be analogous to any other
2 revenue requirement issue where the Company was asking for cost recovery of
3 an item that is supported on the basis of subjectivity and speculation. Regulatory
4 commissions typically disallow these types of requests, as the Commission
5 should here. Further, there are a number of areas in the company's energy
6 efficiency proposal, like the educational and tracking programs, where the
7 Company appears to be asking for recovery for the cost of activities they are, or
8 should be, currently conducting and are currently being recovered in rates.

9 **Q WHAT ARE THE MORE COMMON PRACTICES IN DEVELOPING DSM**
10 **PROGRAMS AROUND THE US?**

11 A DSM development and implementation plans can differ around the
12 country. But there are usually a number of common steps that most utilities, and
13 regulatory commissions, follow. The common filing requirements found in most
14 DSM program filings include:

- 15 • A definition of the overall DSM goals;
- 16 • A complete description of all DSM programs considered including
17 identification of those excluded from the final portfolio and an explanation
18 for the exclusion;
- 19 • Estimated levels of energy and capacity savings, utility costs, and the
20 costs of the planned programs;
- 21 • Complete cost-effectiveness analysis (i.e., comparison of costs to
22 benefits) under standard cost effectiveness tests that include the Total

1 Resource Cost ("TRC") test; the Ratepayer Impact Test ("RIM"); the Utility
2 Cost test, and the Participant test.

- 3 • marketing and delivery plans (including an implementation schedule);
- 4 • measurement and evaluation plans,
- 5 • a description of the administration of the programs.

6 **Q WHAT TYPES OF CALCULATIONS AND ANALYSES ARE TYPICALLY**
7 **DONE BY UTILITIES ONCE THEY HAVE DEFINED THEIR DSM GOALS AND**
8 **POTENTIAL MEASURES?**

9 A Once a list of measures has been developed, each program should be
10 screened for its potential benefits and costs and evaluated in terms of its ability to
11 participate in overall DSM portfolio (i.e., collection of measures and programs).
12 Measures may be eliminated if costs are prohibitively high or if potential savings
13 cannot be verified. This screening and evaluation process is comprised of a
14 number of steps that can include:

- 15 • Calculating incremental costs for each measure. In the case of replacing
16 a natural gas consuming appliance, this is defined as the cost to upgrade
17 to the high efficiency technology. For example, if a standard efficiency
18 water heater costs \$350 and a high efficiency tankless unit costs \$800, the
19 incremental cost would be \$450.
- 20 • Determining incentive levels. Incentive are usually set at levels
21 considered to be large enough to motivate customers to upgrade to more
22 energy efficient appliances. These usually range between 25 percent and

1 50 percent of the incremental cost between the standard efficiency and
2 high efficiency equipment.

3 • Estimating participation rates. Using documentation for similar measures
4 and similar service territories, the Company can estimate the measure-
5 level participation rates. This can take time, especially for utilities initiating
6 DSM programs from scratch.

7 • Interviewing potential vendors. Once the various measures and programs
8 are identified a variety of vendors of energy efficient equipment are
9 typically interviewed for input and recommendations about the uptake of a
10 natural gas DSM program.

11 **Q HOW ARE PROGRAMS TYPICALLY MONITORED?**

12 A The DSM programs need to be continually monitored and evaluated to
13 ensure that they are cost effective and are meeting program goals and
14 representations. Monitoring and evaluation usually includes:

15 • Measuring actual participation rates, energy savings and demand
16 reductions and having a process of comparing these to estimates provided
17 in program development;

18 • Assessing the utility's program implementation process including program
19 marketing and administration;

20 • Examining the need to continue, modify or terminate any given program or
21 sets of programs as events change; and

22 • Determine the persistence and reliability of DSM savings.

1 **Q IS THE COMPANY’S APPROACH CONSISTENT WITH THESE TYPES**
2 **OF PRACTICES?**

3 A No. For instance the Company DSM plan:

- 4 • Does not provide a level of savings goals on an individual measure basis,
5 nor on a total program basis;
- 6 • Does not appear to have considered a wide range of energy efficiency
7 measures, has not clearly identified all energy efficiency measures that
8 were considered and rejected, and the grounds for rejection.
- 9 • Uses relatively subjective participation levels not developed from either
10 industry best practices, prior Michigan experience, or its own experience
11 or market studies. The one exception here would be in the Measures
12 portion of the DSM proposal where some prior studies were referenced for
13 rebate purposes, but nothing else.
- 14 • Is based upon relatively “generalized” cost estimates with little support or
15 backing.
- 16 • Includes no “per measure,” nor “per customer” savings estimates making it
17 impossible to evaluate the potential objective benefits of the program in
18 terms of Dth saved.
- 19 • Most importantly, has not included any cost-effectiveness analysis to
20 determine if the benefits of the program outweigh the costs.
- 21 • Has included no tracking, measurement or verification program to
22 introduce program accountability.

1 Q THE COMPANY HAS CITED A STAFF REPORT ON ENERGY
2 EFFICIENCY AS SUPPORTING ITS CONCLUSIONS THAT IT HAS MET THE
3 NECESSARY REQUIREMENTS FOR SFV APPROVAL. DO YOU AGREE?

4 A No. The Staff report recommended that a:

5 *...utility's fixed cost coverage be considered in association*
6 *with its energy efficiency efforts.* If the utility has a substantial
7 program to assist its customers to use energy more efficiently, then
8 a relatively high fixed cost coverage would be appropriate to assure
9 that the utility is not disadvantaged. Conversely, if the utility does
10 not have a program or *if its program is minor, then little or no*
11 *fixed cost coverage would be justified.*³⁷

12 While the Company is clearly planning on spending a considerable amount on
13 energy efficiency, given the \$2.0 million annual expense included in its requested
14 revenue requirement, these costs are loosely documented and unaccompanied
15 by any serious attempt at examining the overall cost-effectiveness of the
16 program. The incomplete nature of overall program benefits would not meet the
17 Staff Report conclusions and relatively high standards for SFV adoption. Thus,
18 the SFV should be rejected in its entirety for not being accompanied by potential
19 ratepayer benefits that are comparable in magnitude to the new risk they will be
20 accepting under the rather significant change in rate design.

21 **IX. WEATHER NORMALIZATION**

22 Q WOULD YOU PLEASE DISCUSS THE COMPANY'S WEATHER
23 NORMALIZATION PROPOSAL?

24 A Yes. The Company is proposing to change its weather normalization
25 period from 30 years to 15 years if its proposed SFV is not adopted. As I noted

³⁷ Staff Report, *Energy Efficiency Programs*, Michigan Public Service Commission, Response to Order of October 18, 2005, in Case No. U-14667, January 31, 2006, p. 6, *emphasis added*.

1 earlier in my testimony, this normalization is unneeded if the Company's SFV is
2 adopted since it will shift the risk of all weather-related consumption changes
3 onto ratepayers. The Company has based its conclusion on relatively cryptic
4 support referencing the "solid and robust" evidence submitted by a prior
5 Company witness in 2002. This evidence, however, was not submitted as
6 testimony nor an exhibit in this proceeding.

7 **Q DO YOU AGREE WITH THE COMPANY'S PROPOSAL?**

8 A No, I recommend that the Commission reject this alternative proposal for a
9 number of different reasons. First, the adjustment, as noted earlier in my
10 testimony is clearly biased in favor of the Company without any corresponding
11 ratemaking adjustment for this change in risk. Second, the Commission has
12 ruled on this issue in prior gas rate cases and found that the adjustment was not
13 supported. Third, the statistical evidence which usually supports
14 recommendations of this nature is incorrect and typically asks (and answers) the
15 wrong question. Fourth, using a normalization period less than 30 years is not in
16 keeping with the standards used by meteorologists since prior to the Second
17 World War.

18 **Q SINCE YOU'VE ALREADY DISCUSSED THE FIRST ISSUE, LET'S**
19 **TURN TO YOUR SECOND POINT. HOW HAS THE MICHIGAN COMMISSION**
20 **RULED ON SIMILAR PROPOSALS IN THE PAST?**

21 A The Commission has rejected this proposal on at least two different
22 occasions. The first instance of this rejection occurred in the 2004 Consumers
23 Energy rate case (Case No. U-13730) where the Commission rejected a similar

1 proposal by the utility. In that proceeding, the Staff found (and the Administrative
2 Law Judge ruled in favor) that the 15-year proposal was no better than the
3 traditional 30-year normalization period. A year later, the Commission directly
4 ruled against a 15-year normalization proposal by Michigan Consolidated Gas
5 Company ("MichCon"). The Commission accepted the Staff finding that there
6 were no real meaningful differences between the two approaches.

7 **Q DO YOU THINK THE ANALYSES BEING PROMOTED BY UTILITIES**
8 **ON THIS ISSUE ARE ANSWERING THE CORRECT QUESTIONS?**

9 A No. Many utilities are justifying their proposals on some ill-defined
10 conclusions about the root mean square error ("RMSE") as it relates to a
11 comparison of the 15- and 30-year averages. The RMSE is a statistical measure
12 (summary statistic) that is commonly used in time series analysis and
13 forecasting. This measure (in addition to a host of others) can be used as a tool
14 for determining whether one forecast has better predictive capabilities than
15 another. The standard utility argument in favor of a 15-year period is that it has
16 lower RMSE than the 30-year average in predicting, or forecasting, current
17 weather.

18 **Q SO WHY IS THIS THE WRONG QUESTION?**

19 A It's wrong for two reasons. First, the RMSE asks and answers the wrong
20 question: what is the best forecast for weather. This proceeding is based upon a
21 historic test year, not a forecasted one. Thus, the use of the RMSE is irrelevant.
22 Basing part of the rate making process on historic information, and the other on
23 forecasted weather, will represent a mismatch. Second, and most importantly,

1 weather typically moves in cycles where in one period it is warmer than normal,
2 proceeds to normal, and then gets colder than normal. The shifts in these cycles
3 are difficult to predict, which is one of the reasons many analysts have used long
4 run trends.

5 **Q WHAT DOES THIS MEAN IN TERMS OF THE STATISTICS?**

6 A The shorter the period, the more likely the data set is going to reflect more
7 contemporaneous cycles and not longer run trends. From a statistical
8 perspective, it is likely with data of this nature that you will have fewer outliers for
9 more narrowly defined periods, and the standard deviation will be much smaller.
10 In fact, weather data empirical trends show that moving from 30-year averages to
11 5-year averages (in five year increments) results in a linear reduction in the
12 standard deviation of the series as the trend period being averaged gets smaller
13 and smaller. Staff made an important observation in the 2004 Consumers
14 Energy proceeding in looking at this issue when it noted that for five of the last
15 ten years (1993-1997) the 30-year average was closer to the actual HDDs while
16 the more recent five years (1998-2002) was more closely associated with the 15-
17 year average. This would indicate that the 15-year average was more reflective
18 of recent weather cycles than it was the longer run trend. This is the reason
19 why the regulatory process has tended to use longer periods (trends) and not
20 shorter periods (cycles) for ratemaking purposes.

21 **Q IS THE 30-YEAR AVERAGE MORE REFLECTIVE OF WHAT IS**
22 **CONSIDERED NORMAL BY WEATHER SERVICES AND WEATHER**
23 **PROFESSIONALS?**

1 A Yes, the National Oceanic and Atmospheric Administration ("NOAA")
2 defines normal weather periods for 30 years. This standard was adopted at the
3 International Meteorological Conference in Warsaw, Poland in 1935, and
4 adopted by the U.S. during the same period of time. NOAA notes that using the
5 30-year normalization period accounts for slow changes in climate, and not
6 shorter run cycles which can move from cooler to warmer and back to cooler.
7 Obviously, there have been considerable debates in the scientific community,
8 and rather passionate debates in policy circles and the media, about the
9 possibilities (and causes) of global climate change. This debate does have an
10 analogue to the Company's proposal since moving to a 15-year average
11 suggests that the long run "normal" is becoming warmer. Given the wide range
12 of opinion on this issue, I would recommend that the Commission stick with the
13 traditional 30-year average for ratemaking purposes.

14 **X. FINANCIAL ISSUES DRIVING SEMCO'S REVENUE NEUTRALITY**
15 **PROPOSAL**

16 **Q. WHAT IS THE COMPANY'S POSITION CONCERNING ITS DECLINING**
17 **USE PER CUSTOMER AND THE RESULTING IMPACT ON ITS FINANCIAL**
18 **PERFORMANCE?**

19 A. According to the Company, its current volumetric-based rate design does
20 not give it a fair opportunity to recover its costs of providing service to customers
21 and its allowed return.³⁸ The Company believes that its proposed SFV rate
22 design will alleviate these problems. Moving to a fixed rate design will reduce the
23 number of times the Company will have to come before the Commission for rate

³⁸ Direct Testimony and Exhibit of Eugene N. Dubay, 19:2-5.

1 cases,³⁹ and will eliminate revenue and earning losses associated with changing
2 usage patterns.⁴⁰

3 **Q. HOW HAS THE COMPANY'S USE PER CUSTOMER CHANGED OVER**
4 **THE PAST SEVERAL YEARS?**

5 A. The annual trends in the Company's use per customer is shown on Exhibit
6 AG-12. This exhibit presents a 30-year and 15-year normalized use per
7 customer for residential space heating and a 15-year normalized⁴¹ use per
8 customer for total customers. As shown in Exhibit AG-12, the Company's use
9 per customer for residential space heating customers has fluctuated, both
10 increasing and decreasing, but has declined on average by 1.2 percent per year
11 over the last seven years. A more gradual decrease in use per total customer
12 has occurred as well, with an average annual decrease of 0.9 percent over the
13 past seven years.

14 **Q. WHAT HAS BEEN THE TREND IN THE COMPANY'S NUMBER OF**
15 **CUSTOMERS?**

16 A. Recent trends in the Company's total number of customers and residential
17 space heating customers, has been provided on Exhibit AG-13. Over the past
18 seven years, total customers and space heating customers have increased by an
19 annual average of 2.3 percent and 2.2 percent, respectively. During the more
20 recent five years, residential space heating customers grew by a two percent
21 annual average, while total customers increased by some 1.8 percent per year,
22 on average. These rates of growth have slowed in the past three years, with

³⁹ Amended Direct Testimony of Annette Gardiner, P.E., 27:15-19.

⁴⁰ Amended Direct Testimony and Exhibit of Bruce H. Fairchild, 72:7-9.

⁴¹ A 30-year normalized use per customer was not available for total customers.

1 total customers growing by an annual average of 1.5 percent and residential
2 space heating customers growing by an annual average of 1.7 percent.

3 **Q HAS THE DECLINE IN USE PER CUSTOMER RESULTED IN**
4 **SIGNIFICANT DECREASES IN NON-GAS REVENUES?**

5 A No. In fact, Exhibit AG-14 shows that while the Company's gross margin
6 (total revenue less cost of gas sold, or non-gas revenue) has fluctuated over the
7 past several years, it has generally increased since 2000. For instance, the
8 Company's 2000 gross margin was around \$59 million, it fell by about one million
9 dollars in the following year (2001), but increased in both 2002 and 2003 to \$60
10 million and \$64 million, respectively. While margins fell to \$62 million in 2004, it
11 increased in 2005 to almost \$66 million, the highest level over the past five years.

12 **Q WHAT DO THESE GROSS MARGIN TRENDS LOOK LIKE ON A PER**
13 **CUSTOMER?**

14 A The average gross margin per customer has shown a similar pattern
15 fluctuating from year-to-year. These changes are provided on Exhibit AG-15.
16 Gross margin per customer ranged from a low of \$252 in 2001 to a high of \$267
17 in 2005. The Company has been able to increase total non-gas revenue and
18 gross margin per customer since 2000, despite an average decrease in use per
19 customer of some 22 Mcf/year over the past five years.

20 **Q. WOULD YOU EXPECT TRENDS IN THE COMPANY'S FINANCIAL**
21 **SITUATION TO DIRECTLY FOLLOW DECREASES IN USE PER**
22 **CUSTOMER?**

1 A. No and in fact there is a very important “decoupling” mechanism that has
2 existed for a very long time that is often over-looked in this LDC use per
3 customer debate: that mechanism is called a “rate case.” When revenues and
4 net operating income decline due to usage reductions or increases in costs, the
5 Company is free to request rate relief, and the Commission may grant that
6 increase if it is appropriate. This traditional regulatory regime contributes, in a
7 fundamental way, to breaking any direct relationship between declining usage
8 and declining profitability. If energy efficiency did result in a decrease in utility
9 profitability to where the utility’s ability to earn a reasonable return on its
10 investment was challenged, the utility is always free to request a rate increase.

11 **Q. ARE THERE ANY OTHER REASONS WHY PROFITABILITY MAY NOT**
12 **DECREASE?**

13 A. Yes, customer growth also contributes to the Company’s ability to
14 maintain its financial strength. While usage per customer might decline, growth
15 in customers can offset the lost revenues created by this decline. As noted
16 earlier, the Company has seen a relatively consistent increase in customers over
17 the past five years that appears to have helped gross margins.

18 **Q. ARE THERE ANY OTHER REASONS WHY PROFITABILITY MAY NOT**
19 **DIRECTLY FOLLOW USAGE PER CUSTOMER?**

20 A. Costs are the other portion of the profitability equation. If a firm can
21 reduce expenses, or limit the rate at which expenses are rising, it can maintain its
22 profitability. Exhibit AG-15 shows that SEMCO’s operating expenses per
23 customer have generally increased from \$109 per customer in 2000 to \$138 per

1 customer in 2005. This of course has contributed to the Company's inability to
2 achieve its authorized return.

3 **Q. HOW DOES THE TRADITIONAL RATEMAKING PROCESS GIVE**
4 **UTILITIES INCENTIVES TO REDUCE COSTS?**

5 A. The regulatory lag inherent in the traditional ratemaking process gives
6 utilities strong incentives to reduce costs, and potentially increase earnings,
7 during periods between rate cases. While utilities have very little control over
8 their revenues, they have considerable control over their costs. Utilities will need
9 to actively pursue cost efficiency opportunities between rate cases to
10 compensate for unknown changes in revenues, thereby increasing overall
11 profitability. Under the Company's proposed SFV rate design, one-half of a
12 utility's profit function (i.e., revenues) is determined with certainty, thereby
13 substantially reducing any incentive to aggressively manage costs.

14 **Q. WHAT INFORMATION DID THE COMPANY PRESENT IN SUPPORT**
15 **OF ITS CONTENTION THAT IT HAS BEEN UNABLE TO ACHIEVE ITS**
16 **AUTHORIZED RATE OF RETURN UNDER ITS CURRENT RATE DESIGN?**

17 A. The Company presented Exhibit A-12, Schedule 4 which compares the
18 Company's achieved to allowed ROE for the past three years (2003-2005).
19 According to this schedule, SEMCO had an achieved ROE of 8.5 percent, 6.2
20 percent, and 6.4 percent from 2003-2005. These achieved returns are compared
21 to an authorized ROE of 11.4 percent in 2003 and 2004 and an authorized return
22 of 11.0 percent in 2005.

1 **Q. DO YOU BELIEVE THE COMPANY'S PRESENTATION FAIRLY**
2 **REPRESENTS THE IMPACT OF ITS ABILITY TO EARN ITS AUTHORIZED**
3 **RETURN DURING RISING GAS PRICES AND UNDER A RATE DESIGN WITH**
4 **A VARIABLE DISTRIBUTION CHARGE?**

5 A. No, the time period is too short and focuses only on the last three years.
6 Further, there are several conceptual problems with the presentation which
7 understate the achieved returns.

8 **Q. WHY IS THE TIME FRAME TOO SHORT?**

9 A. If the purpose of the analysis is to show the relationship between earnings
10 and gas prices, then it should go back to at least 2000, when gas prices started
11 to increase. The Company's analysis, however, is restricted to only three years
12 (2003-2005). Proposing a dramatic rate increase based upon three years alone,
13 is limiting.

14 **Q. HAVE YOU EXAMINED THE COMPANY'S ACHIEVED RETURNS FOR**
15 **A LONGER PERIOD OF TIME?**

16 A. Yes, I have. The results of my analysis are presented on Exhibit AG-14.
17 This exhibit presents the Company's financial information from 2000 through
18 2005. It also depicts the results as presented by the Company for the years
19 2003 through 2005. The analysis for this entire period (2000-2005) is based
20 upon the same methodology used by the Company.

21 **Q. DOES THIS LONGER TIME PERIOD SHOW THAT THE COMPANY**
22 **HAS CONSISTENTLY BEEN UNABLE TO ACHIEVE ITS AUTHORIZED**
23 **RETURN?**

1 A. No. Exhibit AG-14 shows that SEMCO actually exceeded its authorized
2 ROE in 2000 while approaching that return in 2002. During 2001, 2003, 2004,
3 and 2005 the Company did not achieve its authorized ROE, at least based upon
4 its method of analysis.

5 **Q. ARE THERE ANY PROBLEMS IN THEIR METHOD OF ANALYSIS**
6 **WHICH UNDERSTATES THEIR ACHIEVED RETURNS?**

7 A. Yes. The Company included goodwill and nonutility assets in the rate
8 base used in its analysis despite the fact that the Commission does not allow
9 these assets to be included in rate base for rate making purposes. The Company
10 explained in response to 5-AG-112, that:

11 The MPSC does not include goodwill and non-utility assets in net
12 plant for ratemaking purposes. However, with regard to 2-AG-36,
13 both goodwill and non-utility assets are part of a company's
14 invested capital and therefore are included in an ROE (return on
15 equity) calculation and an ROIC (return on invested capital)
16 calculation.⁴²

17 **Q HOW WILL THE USE OF THESE ITEMS IN ESTIMATING ACHIEVED**
18 **RETURNS BIAS THE ANALYSIS?**

19 A If the components that make up the rate base and capital structure are
20 inconsistent with what the Commission has authorized, accurate conclusions can
21 not be drawn from the comparison. To the extent possible, any comparison
22 between an allowed return and an achieved return should be preformed on a
23 basis consistent with ratemaking allowances by the Commission. The
24 Company's approach essentially assumes that its achieved return should match
25 its allowed return regardless of the Commission's ratemaking practices. Such an

⁴² Response to Attorney General's Fifth Discovery Request to SEMCO Energy Gas Company, 5-AG-112.

1 assumption is unrealistic and unreasonable and leads to erroneous conclusions
2 about the relationship between high gas prices and Company earnings.

3 **Q. WHAT IS THE NEXT CONCEPTUAL PROBLEM WITH THE**
4 **COMPANY'S FINANCIAL ANALYSIS?**

5 A. In the instant and past proceedings, the Company has used an industry
6 average capital structure for purposes of determining its overall cost of capital.
7 According to the Company, the Commission also used industry average capital
8 structure ratios in its last two rate cases.⁴³ Yet despite Commission
9 authorizations, the Company has used an actual capital structure for its financial
10 analysis.

11 **Q WHY DOES THE USE OF THE COMPANY'S ACTUAL CAPITAL**
12 **STRUCTURE BIAS THE ANALYSIS?**

13 A. It would be more appropriate to use a consistent industry average capital
14 structure, as required by the Commission, than the Company's actual capital
15 structure, which was done in the Company's earnings comparison methodology.
16 As I noted earlier, the methodology used to make this comparison should be
17 similar to the one upon which rates are set. If rates are set using an industry
18 average capital structure, but the Company calculated its ROE using its actual
19 equity, only by happenstance would the results match—even if all else were
20 equal.

21 **Q. ARE THERE ANY OTHER METHODOLOGICAL PROBLEMS WITH THE**
22 **COMPANY'S FINANCIAL ANALYSIS?**

⁴³ Amended Direct Testimony of Bruce H. Fairchild, 35:5-7.

1 A. The Company's analysis does not annualize the Commission's rate
2 increases⁴⁴. For example, the Commission authorized a rate increase on March
3 25, 2005. However, the data presented for 2005 contains only nine months of
4 the allowed increase. Restating 2005 to consider the full impact of the
5 Commission's allowed increase would present a more accurate picture of the
6 Company's ability to achieve the Commission's authorized return in that year.
7 This is particularly true because January, February, and March are during
8 SEMCO's peak heating season. Failure to take this into consideration,
9 significantly understates the Company's achieved return relative to its allowed
10 return.

11 **Q. ARE THERE ANY ADDITIONAL METHODOLOGICAL CONCERNS**
12 **ABOUT THE COMPANY'S ANALYSIS?**

13 A. Yes, the financial information is based upon a partial year's worth of
14 revenue, expenses and rate base for the Company's acquisition of Peninsular
15 Gas Company (PenGas). The Company's financial results include PenGas data
16 from June 2005 through December 2005.⁴⁵ Generally this would not be a
17 problem because the Company utilizes an average rate base. However,
18 because of the seasonal nature of PenGas' operations, exclusion of the first six
19 months of 2005 data reduces the Company's achieved return. Using the
20 Company's proforma adjustment for PenGas shows that during the first five

⁴⁴ During the period 2000 through 2005, the Commission authorized two rate increases. One in May 2003 and the other in March 2005. Only data for the 2005 increase was readily available and used on Exhibit AG-12.

⁴⁵ Response to Attorney General's Second Discovery Request to SEMCO Energy Gas Company, 2-AG-35.

1 months of 2005⁴⁶, PenGas' operations earned a 38 percent return on
2 investment. Thus, excluding the most profitable season associated with PenGas'
3 operations from the financial presentation understates the Company's ability to
4 earn the Commission's authorized return. This represents yet another bias in the
5 Company's comparison of its actual to achieved returns in the face of changes in
6 natural gas markets.

7 **Q. HAVE YOU CONDUCTED ANY FINANCIAL ANALYSIS WHICH**
8 **CORRECTS FOR ALL OF THE PROBLEMS YOU HAVE JUST DISCUSSED?**

9 A. Yes, this analysis has been provided on Exhibit AG-14. The analysis
10 corrects for all of the errors I discussed earlier. The corrected results reveal
11 considerable differences from those presented by the Company. For instance, in
12 2002, the Company's achieved return on equity increased from 10.11 percent to
13 11.43 percent – a financial result in excess of the Commission's allowed ROE of
14 10.75 percent. In 2005, the Company's achieved ROE increases from 6.43
15 percent to 8.38 percent once these errors I discussed earlier are corrected. The
16 overall return for that year (2005) increases from 6.96 percent to 7.84 percent, or
17 0.88 percent above the return allowed by the Commission.

18 **Q. WHY IS IT THAT THE COMPANY APPEARS TO BE EARNING ITS**
19 **AUTHORIZED RETURN ON RATE BASE, BUT NOT ITS AUTHORIZED**
20 **RETURN ON EQUITY IN 2005?**

⁴⁶ There appears to be an inconsistency between the Company's testimony and response to Attorney General Data Request 1-AG-35 both of which indicate that PenGas' operations are reflected in 2005 test year from June 2005 through December 2005. However, Exhibit A, Schedule B-4, which calculates the rate base adjustment, shows a five month annualization for PenGas.

1 A. This is partly related to the issuance of additional long-term debt during
2 2005. This, in turn, caused an increase in interest expense which lowered the
3 Company's net income available to stockholders. The result reduced the return
4 on equity, but not the return on rate base.

5 **Q. IN SUMMARY, DO YOU THINK FROM A FINANCIAL PERSPECTIVE**
6 **THAT THE COMPANY HAS CLEARLY DEMONSTRATED THAT THE**
7 **DECLINE IN USE PER CUSTOMER NECESSITATES A SUCH RADICAL**
8 **CHANGE IN RATE DESIGN?**

9 A. No, it has not. There are several reasons why the Company's achieved
10 return has deviated from the Commission's allowed return, only one of which is
11 related to a decline in use per customer. Further, there are other factors that
12 have offset the impact of declining usage that includes customer growth.
13 Moreover, as demonstrated above, the Company's achieved returns are
14 considerably higher than the returns presented by the Company once a number
15 of methodological corrections are made to their financial analysis. The limited
16 financial analysis presented by the Company should be rejected in conjunction
17 with its request to changed to a SFV rate design.

18 **XI. THE COMPANY'S LAUF AND UNCOLLECTIBLES PROPOSAL**

19 **Q. HOW IS THE COMPANY PROPOSING TO RECOVER THE COST OF**
20 **LAUF GAS?**

21 A. The Company is proposing two alternative treatments for the recovery of
22 LAUF gas costs. Its preferred methodology is to remove LAUF costs from base
23 rates and recovery them in the GCR. Under this method, LAUF would be

1 recovered monthly as a booked gas cost in the GCR rate. It would be subject to
2 the same annual review process as other GCR costs. If the Commission does
3 not approve its preferred GCR cost recovery plan, SEMCO proposes to keep
4 LAUF costs in base rates and perform an annual true-up of actual to allowed
5 LAUF costs.

6 **Q. CAN YOU EXPLAIN WHAT IS MEANT BY THE TERM LOST AND**
7 **UNACCOUNTED FOR (LAUF) GAS?**

8 A. Yes. LAUF gas is the difference between gas received into the
9 Company's system and gas delivered to end use customers. The difference is
10 attributable to a number of causes, which the Company described as:

11 ...differences may be due to quantities of natural gas lost through
12 leaks, because of damage to the Company's system causing an
13 escape of gas, or to the effects of data reporting problems and
14 errors. Reporting problems include differences due to the net result
15 of conversions of flow data metered at varying temperatures and
16 pressures and converted to a standard temperature and pressure,
17 the effect of variations in Company accounting and billing practices;
18 differences between billing cycle and calendar-period timeframes;
19 and imbalances resulting from the merger of data reporting systems
20 that vary in scope, format, definitions, and type of respondents.⁴⁷

21 **Q. ARE THERE OTHER VARIABLES THAT MAKE UP LAUF GAS?**

22 A. Yes. In addition to losses and potential errors, the LAUF includes gas
23 used by the Company ("Company Use") in the operation of its transportation and
24 distribution system. Company Use gas is not always separately identified when
25 discussing LAUF, but is a component of LAUF gas costs, and is included in the
26 Company's proposed methods of LAUF cost recovery.

⁴⁷ Direct Testimony and Exhibit of Eugene N. Dubay, 21-22:14-1.

1 **Q. CAN YOU PLEASE DISCUSS THE COMPANY'S PAST LAUF**
2 **TRENDS?**

3 A. Trends in the Company's LAUF gas volumes are summarized on Exhibit
4 AG-16. As the exhibit shows, volumes increased in 2001-02, they decreased
5 during the years 2002-03⁴⁸ and 2003-04, and they increased in the year 2004-05.
6 In response to 2-AG-83, the Company explained that the decline in LAUF gas in
7 2003-04 was the result of two adjustments booked in December 2003. One
8 adjustment, discovered through well-testing, resulted in an increase of gas
9 volumes 172,737 Mcf more than previously anticipated. The second adjustment
10 was to correct a pipeline meter error that lasted 14-16 months resulting in a
11 found gas adjustment of 65,526 Mcf.⁴⁹

12 **Q. HOW DOES SEMCO CURRENTLY RECOVER ITS LAUF GAS COSTS?**

13 A. LAUF costs, including Company Use gas costs, are recovered as a
14 component of base rates. The mechanics of the cost calculations follow a
15 number of steps. First, SEMCO calculates a simple average of the percentage of
16 total throughput that is LAUF gas for the most recent five years. Second, the five
17 year average LAUF percentage is multiplied times the test year total throughput
18 to calculate the volume of LAUF gas for the test year. A similar calculation is
19 performed to determine test year Company Use gas, multiplying the Company
20 Use percentage of total throughput for the most recent year times the test year
21 throughput volume. Third, the sum of LAUF and Company Use Gas is adjusted

⁴⁸ The Company's LAUF volumes are accounted for from September through August.

⁴⁹ Response to Attorney General's Fifth Discovery Request to SEMCO Energy Gas Company, 5-AG-132.

1 for the Gas in Kind (GIK)⁵⁰ of the transportation customers. Fourth, the resulting
2 (adjusted) total is multiplied times the test year weighted average cost of gas.
3 Using this methodology, the cost of LAUF (including Company Use, and net of
4 GIK) gas in the current rate case equals \$4,575,161 for the 2007 test year.

5 **Q. WHY IS THE COMPANY PROPOSING TO MOVE LAUF GAS FROM**
6 **BASE RATES AND PUT THEM IN THE GCR?**

7 A. SEMCO argues that by including LAUF costs in base rates, in a time of
8 natural gas price volatility, the Company is precluded from ever recovering its
9 actual LAUF gas costs. Witness Gardiner states:

10 When LAUF is managed well, as is the case at SEMCO Gas, the
11 key variable that determines the Company's LAUF gas costs is the
12 price of gas, including price volatility. If natural gas prices increase
13 substantially, the Company's allowance for LAUF gas costs in base
14 rates does not match the expense actually incurred by the
15 Company, by a substantial amount. The result, in this scenario, is
16 that the Company never recovers a legitimate cost of providing
17 service to customers.⁵¹

18 According to Ms. Gardiner, SEMCO manages its LAUF as a safety
19 concern. Leaks, a large component of LAUF, are identified and repaired as a
20 matter of safety. Thus, SEMCO argues it needs no incentive from the regulatory
21 lag resulting from including LAUF in base rates. In support of this position,
22 SEMCO compares its LAUF as a percentage of throughput to the industry
23 average reported by the American Gas Association ("AGA"). SEMCO's LAUF
24 percentage was 1.124 percent in 2000-2001, 1.463 percent in 2001-2002, 0.934

⁵⁰ Transportation customers are not charged for LAUF and Company Use gas in their rates. Instead, the Company retains a percentage of all gas received into its system for delivery to its Transportation customers. This Gas in Kind (GIK) percentage is the sum of LAUF and Company Use Gas as a percentage of throughput.

⁵¹ Amended Direct Testimony and Exhibits of Annette Gardiner, P.E., 33:4-10.

1 percent in 2002-2003, 0.592 percent in 2003-2004, and 0.966 percent in 2004-
2 2005.⁵² The Company compares these percentages to the industry average
3 reported by the AGA of 1.23 percent for 2003.^{53,54} Comparisons for other time
4 periods was not provided by the Company and the AGA Benchmark Reports
5 provided in response to discovery did not contain similar statistics. Therefore,
6 while the Company's LAUF gas appears to be at or below the industry average,
7 additional data would need to be provided to confirm this characterization.

8 **Q. THE COMPANY CLAIMS THAT LAUF GAS COSTS ARE TREATED AS**
9 **A COMPONENT OF GAS COSTS IN A MAJORITY OF JURISDICTIONS IN**
10 **THE UNITED STATES. (GARDINER, P. 32) DO YOU AGREE?**

11 A. The Company prepared Exhibit A-12 Schedule 7, which depicts the
12 methodology allowed by certain gas companies for recovering LAUF gas costs.
13 This exhibit, which Ms. Gardiner apparently relied upon to make her statement, is
14 not inclusive of all gas distribution companies in the nation—it only includes 45
15 companies of almost 200 companies that are members of the AGA and the 271
16 investor owed gas distribution companies that report to the U.S. Department of
17 Energy.

18 Of the 45 companies listed on the Company's exhibit, there are 11 where
19 it is clear from the exhibit that LAUF is included in the gas cost recovery
20 mechanism. Of the other companies, some are specifically prohibited from

⁵² Response to Attorney General's Second Discovery Request to SEMCO Energy Gas Company, 2-AG-78.

⁵³ It is unclear how many utilities are included in the AGA benchmarking report, how their calculations were performed, and how comparable the AGA percentage is to those calculated by SEMCO.

⁵⁴ Amended Direct Testimony and Exhibits of Annette Gardiner, P.E., 32-33:20-2.

1 including LAUF in GCR type mechanisms, in other instances the tariff is
2 ambiguous as to what costs are passed through the GCR. Some companies
3 employ true-up mechanisms for LAUF costs, some tariffs do not address the
4 issue at all, and some include the costs in base rates.

5 **Q IS THE INFORMATION PROVIDED BY THE COMPANY AMBIGUOUS**
6 **RELATIVE TO CERTAIN COMPANIES?**

7 A Yes. For example, the entry for Ameren-Central Illinois Light on the
8 exhibit shows “no prohibition to recovery in PGA [purchased gas adjustment]” —
9 this description says nothing about how these costs are treated, only that they
10 can be included in the PGA. Another example includes Berkshire Gas which
11 states that “Company gas allowance recovered in LAUF.” This entry gives no
12 information about how LAUF gas costs are recovered. The exhibit is useful in
13 showing the variety of Commission practices regarding LAUF cost recovery, but
14 it does not provide overwhelming evidence that the recovery of LAUF gas in
15 GCR-type mechanisms is the rule rather than the exception.

16 **Q. DO YOU AGREE WITH THE COMPANY THAT LAUF COSTS MUST BE**
17 **REMOVED FROM BASE RATES OR TRUED-UP ANNUALLY IN ORDER FOR**
18 **THE COMPANY TO FULLY RECOVER THESE COSTS?**

19 A. No, I do not. The Company notes that: “If natural gas prices increase
20 substantially, the Company’s allowance for LAUF gas costs in base rates does
21 not match the expense actually incurred by the Company, by a substantial

1 amount. The result, in this scenario, is that the Company never recovers a
2 legitimate cost of providing service to customers.⁵⁵

3 **Q DO YOU AGREE THAT THIS IS UNIVERSALLY THE CASE?**

4 A No. The Company's claim is true only during times of rising gas prices.
5 However, gas prices are not always increasing. When natural gas prices
6 increase, the Company's LAUF allowance, set in earlier rate case proceeding, is
7 not sufficient to recover the actual expenses now incurred. However, when
8 natural gas prices decline, the Company stands to recover an amount greater
9 than the actual cost of its LAUF gas.

10 **Q. ARE THE COSTS ASSOCIATED WITH LAUF GAS PURELY A**
11 **FUNCTION OF THE COST OF NATURAL GAS?**

12 A. No. LAUF gas costs are a function of both the cost of natural gas and the
13 volume of LAUF gas. While the former may be largely considered beyond the
14 control of the Company, the latter is not. The Company exerts considerable
15 control over the volume of its LAUF gas. For example, in response to the
16 Attorney General's data request 5-AG-130, when asked to describe efforts to
17 control LAUF, the Company replied:

18 The Company employs a variety of measures to address the causes of LAUF
19 gas. These measures include:

⁵⁵ Amended Direct Testimony and Exhibits of Annette Gardiner, P.E., 33:6-10.

- 1 • Performing meter testing to meet or exceed the Public Service
2 Commission's "Technical Standards for Gas Service" that govern the
3 testing and installation of meters.
- 4 • Verifying all receipt point inventories with measurement records from the
5 supplier and developed an exception report to identify significant
6 measurement issues quickly.
- 7 • Replaced measurement equipment at compressor station
- 8 • Utilize worker/monitor configuration for new regulating stations to reduce
9 lost gas when compared to a regulator and relief valve configuration.
- 10 • Evaluate new product available to reduce lost gas, such as pilot gas
11 heaters used in place of catalytic heaters in district regulator stations.
12 These heaters use thermodynamic properties of the gas that result in no
13 lost gas.
- 14 • Perform leak survey to meet or exceed the requirements of the "Michigan
15 Gas Safety Standards". Surveys include pre- and post-construction
16 surveys to identify leaks caused by third party construction.
- 17 • Work diligently to identify and reduce theft utilizing the automated meter
18 reading equipment that identifies tampering and meter moves (including
19 unauthorized meter change-outs). Meters are removed from premises that
20 have unpaid accounts exceeding 18 months.⁵⁶

21 **Q. IS THE RECOVERY OF LAUF GAS IN THE RATE SETTING PROCESS**
22 **FAIR AND REASONABLE?**

⁵⁶ Response to Attorney General's Fifth Discovery Request to SEMCO Energy Gas Company, 5-AG-130.

1 A. Yes. The recovery of LAUF in the rate setting process balances the
2 interest of ratepayers and stockholders. While the Company would prefer that
3 these costs be automatically passed through to ratepayers in the GCR,
4 ratepayers would prefer that the Company be provided with an incentive to
5 manage these costs. This incentive is provided by having these costs included in
6 the traditional rate making process and not the GCR. The time period between
7 rate cases provides an incentive for the Company to keep the LAUF volumes at
8 their lowest possible levels. Furthermore, differences between actual and
9 allowed LAUF dollars can turn in the Company's favor if gas prices fall relative to
10 the level set in the last base rate case. In such instances, the Company will
11 actually be allowed to retain these differences if they are higher than those
12 anticipated in the last rate case.

13 **Q. WHAT HAS BEEN THE COMMISSION'S POLICY WITH RESPECT TO**
14 **RECOVERING COSTS RELATED TO LAUF GAS?**

15 A. This Commission has ruled that LAUF costs should not be recovered
16 through the GCR. This policy was recently articulated by the Commission in April
17 2006. In a ruling concerning SEMCO's application for a low-income gas cost
18 assistance pilot program, which also featured moving recovery of LAUF from
19 base rates to the GCR, the Commission stated:

20 While the Commission applauds any effort designed to aid
21 disadvantaged Michigan citizens, the Commission does not foresee
22 any event or instance in which the common practice of recovering

1 uncollectibles and LAUF gas expenses in a general rate case
2 would change.⁵⁷

3 **Q. HAS THE COMPANY PRESENTED ANY EVIDENCE THAT WOULD**
4 **INDICATE THAT THE COMMISSION SHOULD CHANGE ITS POLICY?**

5 A. No. The circumstances that existed in Case No. U-14649 are not
6 materially different from the circumstances that exist now. The Company has not
7 provided any new meaningful information that would warrant that the
8 Commission should change its policy.

9 **Q. WHAT IS YOUR RECOMMENDATION?**

10 A. I recommend that the Commission reject the Company's request to
11 include its LAUF gas costs in its GCR. Likewise, it should reject SEMCO's
12 request to annually true up these costs. This request, like all the other risk
13 shifting proposals included in its application (i.e., SFV rate design, a shorter
14 weather normalization period, and recovery of its uncollectibles expense) clearly
15 benefits shareholders without any corresponding benefit to ratepayers in the form
16 of any reduction in its proposed ROE. This is an issue I discussed earlier, and
17 will expand on in a later part of my testimony as it relates to both the LAUF and
18 uncollectibles expense recovery proposals.

19 **Q. WOULD YOU PLEASE DISCUSS THE COMPANY'S**
20 **UNCOLLECTIBLES EXPENSE RECOVERY PROPOSALS?**

⁵⁷ In the matter of the application of SEMCO Energy Gas Company for authority to implement a pilot gas cost assistance program in its MPSC Division, to recover costs related to the program, and related approvals, Case No. U-14649, Michigan Public Service Commission, April 25, 2006.

1 A. SEMCO proposes that an annual true-up be performed on its
2 uncollectibles expense. The true-up would compare those expenses recovered
3 through base rates with the Company's actual annual uncollectible expense. As
4 with its proposed true-up of LAUF costs, any over-recovery would be refunded to
5 customers, while any under-recovery would be surcharged to customers.

6 **Q HOW WOULD THIS TRUE-UP WORK?**

7 A The Company explains that each calendar year SEMCO would report to
8 the MPSC the amount by which the Company's actual uncollectible expense
9 either exceeded or was less than the amount determined in this case to be just
10 and reasonable. This difference would then be refunded (or surcharged) to
11 customers by allocating the total difference among customer classes in the same
12 manner as included in its current class cost of service study. Each customer
13 class refund (surcharge) amount would be divided by the number of customers in
14 that class to determine the refund (surcharge) due each customer.⁵⁸

15 **Q. HOW HAS THE COMPANY'S UNCOLLECTIBLES EXPENSE**
16 **CHANGED RECENTLY AND HOW DOES IT COMPARE TO OTHER**
17 **COMPANIES?**

18 A. Uncollectibles expense in 2005 totaled \$1,587,080, or 0.41 percent of
19 sales. This was an increase from the 2004 level of \$1,408,793, although it
20 represented a decrease in uncollectibles as a percent of sales which was 0.44
21 percent in 2004. The Company's uncollectible expense compared favorably to
22 industry averages which would suggest that the current ratemaking treatment of

⁵⁸ Amended Direct Testimony and Exhibits of John Alger, 16-17:17-15

1 these costs is working well. In 2004, SEMCO's uncollectibles expense were
2 reported as \$5.89⁵⁹ per customer, compared to an industry wide average of
3 \$15.20 per customer – or some 61 percent lower.⁶⁰

4 **Q. DO YOU AGREE WITH THE COMPANY CLAIMS THAT THE MPSC**
5 **ACTIONS ARE TO BLAME FOR INCREASED UNCOLLECTIBLES?**

6 A, SEMCO states that the emergency rules adopted in U-14668 have
7 contributed to the increase in uncollectibles expense. These rules included many
8 changes to help customers maintain service through the winter months from
9 November 1, 2005 through March 31, 2006. The rules extended the "no shut-off"
10 period of the Winter Protection Program, lengthened the time before a bill's due
11 date, changed the shut-off rules for senior citizens and low income customers,
12 among other changes. The Company notes that from its perspective:

13 ...the influence of Commission rules on the Company's
14 Uncollectible expense experience is another reason for an annual
15 true-up of this expense item. That way, the impact of MPSC rule
16 changes affecting Uncollectible expense will be reflected promptly
17 in amounts charged to customers. Without such a true-up, an
18 MPSC rule change would have the effect of impairing the
19 Company's ability to recoup its costs of providing service.⁶¹

20 The emergency rules in U-14668 were adopted for the winter months of 2005
21 through 2006.⁶² The Company also notes that the Commission Staff is now
22 proposing that these emergency rules be made permanent, and that Staff is

⁵⁹ The amount reported in the AGA 2005 Best Practices Benchmarking Report is different that the amount reported on my Exhibit AG-17 due to different customer numbers between the two sources.

⁶⁰ Response to Attorney General's Second Discovery Request to SEMCO Energy Gas Company, 2-AG-55 (2005 Best Practices Benchmarking Report, American Gas Association).

⁶¹ Amended Direct Testimony and Exhibits of Annette Gardiner, P.E., 39:16-21.

⁶² In the matter, on the Commission's own motion, to adopt emergency rules regarding billing practices for retail customers of electric and gas utilities subject to the Commission's jurisdiction, Case No. U-14668, Order Commencing Emergency Rulemaking Proceeding, October 18, 2005.

1 proposing additional changes to residential and commercial customer billing
2 rules.⁶³

3 **Q. HAS SEMCO QUANTIFIED THE IMPACT OF THE EMERGENCY**
4 **RULES VERSUS RISING GAS PRICES?**

5 A. No it has not. The Company notes that that 2005 uncollectible expense
6 increased by \$178,000, but this increase is not broken out between the increase
7 attributable to rising gas prices, those attributable to changes in Commission
8 rules, and those related to other economic factors.⁶⁴

9 **Q. WHAT OTHER REASONS DOES SEMCO CLAIM ARE THE CAUSE**
10 **FOR ITS INCREASED UNCOLLECTIBLE EXPENSE?**

11 A. SEMCO states that the rising gas prices experienced last winter made it
12 more difficult for customers to pay their bills and was one of the root causes of
13 the increase in uncollectibles expense. In discussing the increase in
14 uncollectibles expense between 2004 and 2005, the Company claims that:

15 The reason for this increase is the market price of gas. When gas
16 prices increase significantly and gas costs comprise about 80% of
17 the average residential customer bill, customers typically have
18 more difficulty in paying their bills for service – and the Company's
19 Uncollectible expense increases, again largely because of the
20 increase in the market price of gas.⁶⁵

21 While natural gas commodity prices are undoubtedly important, total bills (upon
22 which uncollectibles are derived) can be a function of a host of factors influencing
23 natural gas demand including general economic conditions and weather and a

⁶³ Direct Testimony and Exhibit of Expert Witness Daniel J. Forsyth, 1-2:23-6.

⁶⁴ Amended Direct Testimony and Exhibits of Annette Gardiner, P.E., 37:17-28.

⁶⁵ Amended Direct Testimony and Exhibits of Annette Gardiner, P.E., 37:20-25.

1 many other factors that are part of the risk associated with operating in the
2 energy business.

3 **Q. HAVE YOU FOUND ANY INFORMATION WHICH SUPPORTS THE**
4 **COMPANY'S CLAIM THAT RISING GAS PRICES CONTRIBUTE TO RISING**
5 **UNCOLLECTIBLES?**

6 A. Not really. Recent trends in these expenses have been shown on Exhibit
7 AG-17. While the Company cites the 2004 to 2005 uncollectibles expense
8 increase as being especially problematic, there was a decrease in the
9 percentage of uncollectibles relative to total revenues (0.44 percent to 0.41
10 percent) during that same period. This is a very small decrease considering gas
11 cost per customer increased by 24 percent during the same period.
12 Uncollectibles on a per customer basis show a moderate increase of 11 percent
13 from 2004 to 2005, while these expenses as a share of total gas costs remained
14 relatively flat from 0.516 percent to 0.578 percent

15 **Q. WHAT ABOUT TIME PERIODS PRIOR TO 2004 AND 2005 DOES THE**
16 **DATA THAT YOU HAVE EXAMINED SHOW THAT INCREASED GAS COSTS**
17 **SHOW A COMMENSURATE INCREASE IN UNCOLLECTIBLES?**

18 A. No. The information presented on Exhibit AG-17 does not support a
19 contention that rising gas costs necessarily produce higher relative
20 uncollectibles. From 2000 to 2001, the cost of gas per customer increased from
21 \$473 to \$488. Uncollectibles for the same time increased also from \$2.55 to
22 \$3.00. While the pattern was the same, the increase in uncollectibles per
23 customer was 17.9 percent whereas the increase in gas costs was only 3.1

1 percent. From 2001 to 2002, the cost of gas per customer increased 24 percent
2 from \$488 to \$606, yet uncollectibles per customer increased less than 2 percent
3 from \$3.00 to \$3.05 during this same period.

4 **Q CAN YOU EXPLAIN THE CHANGES IN UNCOLLECTIBLES FOR 2003?**

5 A During 2003, uncollectibles expense showed a dramatic increase relative
6 to 2002—increasing from \$718,150, or \$3.05 per customer in 2002 to
7 \$2,277,125, or \$9.51 per customer in 2003. On a per customer basis, this
8 represented an increase in uncollectibles expense of over 100%. However, as
9 depicted on this exhibit, the cost of gas per customer increased by 53.9 percent.
10 According to the Company's 2004 Annual Report, the local economy and large
11 customer bankruptcies were the cause of the increase in uncollectibles, not
12 increased gas prices.⁶⁶

13 **Q WHAT HAPPENED IN THE SUBSEQUENT YEAR?**

14 A Changes between 2003 and 2004 appear to show an inverse relationship
15 between uncollectibles and gas costs per customer. For example, from 2003 to
16 2004, the cost of gas increased from \$932 per customer to \$1,009 per customer.
17 Uncollectibles expense, however, decreased from \$9.51 per customer to \$5.80
18 per customer. However, this relationship is mostly likely due to the fact that the
19 large customer write-offs that took place in 2003 did not exist in 2004.⁶⁷

20 **Q. DO OTHER JURISDICTIONS EMPLOY A TRUE-UP MECHANISM AS**
21 **PROPOSED BY SEMCO FOR UNCOLLECTIBLES EXPENSE?**

⁶⁶ SEMCO Energy Inc, Form 10-K, Filed with the US Securities and Exchange Commission, for the Fiscal Year Ended December 31, 2004, p. 23.

⁶⁷ SEMCO Energy Inc, Form 10-K, Filed with the US Securities and Exchange Commission, for the Fiscal Year Ended December 31, 2005, p. 37.

1 A, Some do, but it is not a common practice. The Company shows on
2 Exhibit A-12 Schedule 7, that there are a number of mechanisms used to recover
3 uncollectibles expense. Utilities in several jurisdictions, including Illinois, Indiana,
4 Maryland, Kentucky, New Jersey, New York, Minnesota, Wisconsin, Oklahoma,
5 and Virginia, recover uncollectibles expense as SEMCO does, through base
6 rates. In New York State, utilities are now separating uncollectibles into those
7 associated with gas costs and those associated with distribution cost where only
8 the gas cost uncollectibles will be recovered through a surcharge on gas costs.
9 Utah follows a similar process where only the gas portion of uncollectibles is
10 accounted for in their GCR.

11 **Q. THE COMPANY HAS USED MICHCON'S ALLOWED TREATMENT OF**
12 **UNCOLLECTIBLES IN SUPPORT OF ITS PROPOSAL. WHAT DID THE**
13 **COMMISSION FIND IN THAT CASE?**

14 A. In Case No. U-13898, Order dated April 28, 2005, the Commission
15 approved MichCon's proposed Uncollectible Expense Tracking Mechanism
16 ("UETM"), however it only allowed MichCon to recover 90 percent of its actual
17 uncollectible expense not included in base rates. Full recovery was not allowed
18 because the Commission found that MichCon should remain at risk for 10
19 percent of its uncollectibles expense to provide an incentive to minimize its actual
20 expense level. Moreover, the UETM appears to be a temporary mechanism since
21 the Commission noted: "...it is appropriate to consider an increased cost level for

1 purposes of this proceeding only.⁶⁸ MichCon was directed to develop a low-
2 income energy efficiency funding program in its next rate case as a means to
3 help offset its uncollectible problems.⁶⁹

4 **Q. ARE THE CIRCUMSTANCES OF MICHCON AND SEMCO THE SAME?**

5 A. No, they are not. For starters, MichCon presented evidence in its last rate
6 case that showed its service territory contained 50 percent of the state's low
7 income population. SEMCO has not presented any information that would
8 suggest it is similarly situated. Also, MichCon and SEMCO have substantially
9 different uncollectibles expenses standardized on a per customer basis.
10 According to the AGA 2005 Best Practices Benchmarking Report, SEMCO's bad
11 debt expense per customer was \$5.89 while MichCon's was \$52.64 -- quite a
12 large difference.

13 **Q. WHAT IS YOUR RECOMMENDATION CONCERNING THE**
14 **COMPANY'S UNCOLLECTIBLES EXPENSE RECOVERY PROPOSAL?**

15 A. I recommend that the Commission reject the Company's request. SEMCO
16 has not shown that there are sufficient reasons for the Commission to change its
17 long-standing practice of including uncollectibles expense in base rates and
18 putting the Company at risk (or reward) for changes between rate cases.
19 SEMCO has failed to show that rising gas prices have consistently contributed to
20 rapidly rising uncollectibles expenses. Moreover, SEMCO has not demonstrated

⁶⁸ In the matter of the application of Michigan Consolidated Gas Company for authority to increase its rates and for other relief; In the matter of the application of Michigan Consolidated Gas Company for approval of depreciation accrual rates and other related matters, Michigan Public Service Commission, Case No. U13989, Case No. U-13899, Opinion and Order Granting Rate Relief, File Date April 28, 2005, p. 31, *emphasis added*.

⁶⁹ Ibid

1 that the risks associated with recovery of increased uncollectibles expense
2 should be shifted from shareholders to ratepayers.

3 **Q. IF THE COMMISSION WERE TO GRANT THE COMPANY'S REQUEST**
4 **WITH RESPECT TO LAUF GAS COSTS AND UNCOLLECTIBLES EXPENSE,**
5 **HOW WOULD THIS AFFECT THE COMPANY'S RISK?**

6 A. If the Commission grants the Company's requests, SEMCO's risk would
7 be lowered. Like its other proposals, these requests move the risk of managing
8 LAUF costs and uncollectibles from stockholders, where they belong, to
9 ratepayers. The Company is in a much better position to manage these risks
10 than its customers. These expenses are part of the costs of doing business and
11 can increase for a variety of reasons, including increased gas costs, challenging
12 regional economic activity, and poorly managed LAUF gas and uncollectibles.
13 The Company's stockholders should be expected to bear these risks which is
14 one of several reasons why they earn a return higher than the risk free rate.

15 **Q. HAS THE COMPANY ADJUSTED ITS COST OF EQUITY TO TAKE**
16 **INTO CONSIDERATION ITS REQUESTS CONCERNING LAUF GAS AND**
17 **UNCOLLECTIBLES?**

18 A. It has not made an adjustment but does recognize this as an issue. The
19 Company has estimated its cost of equity using both a discounted cash flow
20 analysis ("DCF") and an industry analysis. The cost of equity estimated under
21 the industry analysis assumes that LAUF is recovered through the GCR and not
22 the Company's base rates.

23 LAUF gas costs are not normally treated as a component of gas
24 utilities' base rates, as is currently the case with SEMCO Gas.

1 Rather, the customary practice across the U.S. is to treat the cost
2 of LAUF as part of the cost of gas, as SEMCO is proposing.
3 Therefore, the industry cost of equity estimated earlier essentially
4 presumes that LAUF gas costs will be fully recovered (subject, of
5 course, to a review of reasonableness) through the cost of gas.
6 Indeed it is arguable that if LAUF gas costs continue to be included
7 in SEMCO Gas's base rates, then an upward adjustment to the
8 industry cost of equity would be necessary to account for the
9 uncertainty associated with the collection of this volatile expense.⁷⁰

10 **Q. HAS THE COMPANY PROVIDED ANY SUPPORT FOR THESE**
11 **RATHER SWEEPING CONCLUSIONS ABOUT THE RATEMAKING**
12 **TREATMENT OF LAUF EXPENSES?**

13 A. No, the Company has provided no evidence regarding how the utilities
14 included in the industry group recover LAUF gas costs. If one were to assume
15 that the group utilized by the Company is comparable to the one shown on
16 Exhibit A-12 Schedule 7, then only 25 percent of the peer group have
17 unambiguous GCR-type LAUF expense recovery mechanisms.

18 **Q. DID THE COMPANY MAKE AN ADJUSTMENT FOR THE REDUCTION**
19 **IN RISK ASSOCIATED WITH THE PROPOSED CHANGE IN**
20 **UNCOLLECTIBLES EXPENSE?**

21 A. No. Here again, the Company dismissed any such adjustment. The
22 Company notes that because the true-up involves only the amount above or
23 below the expenses included in base rates,

24 [s]o long as a realistic allowance for uncollectibles accounts
25 expense is included in base rates, whether it is trued-up is not likely
26 to be a major area of concern to the investment community. As a
27 result, SEMCO Gas's proposed true-up is not apt to have a material
28 effect, one way or the other, on investors' required rate of return.⁷¹

⁷⁰ Amended Direct Testimony and Exhibit of Bruce H. Fairchild, 70:11-21.

⁷¹ Amended Direct Testimony and Exhibit of Bruce H. Fairchild, 71:4-9.

1 **Q DO YOU AGREE WITH THE CONCLUSION THAT THE INVESTMENT**
2 **COMMUNITY IS NOT LIKELY CONCERNED ABOUT THE RATEMAKING**
3 **TREATMENT OF UNCOLLECTIBLES AND LAUF?**

4 A No, not at all. As I noted earlier, many financial analysts have become
5 increasingly concerned about the regulatory treatment of costs they believe are
6 negatively impacted by changes in natural gas markets. Clearly, regulatory
7 issues of revenue neutrality and weather normalization are the leading concerns
8 for many of these analysts, but they have also expressed an interest in those
9 LDCs that are able to secure favorable uncollectibles and LAUF ratemaking
10 treatment as well. For instance, in May 2006, Janney Montgomery Scott, LLC in
11 a report on the natural gas industry, noted that “[b]ad debt expense are normally
12 recovered as fixed costs in base rates. Higher than projected bad debt levels
13 usually result from significant increases in gas costs, which are outside of the
14 LDC’s control. Unless mitigated by a regulatory authority, the higher expense will
15 reduce the LDC’s return.”⁷² Likewise, a November 2005 report by the firm
16 Natexis Bleichroeder Inc. included both reserves for bad debt and higher lost gas
17 costs as major issues affecting the Company.⁷³

18 **Q. IF THE COMMISSION WERE TO GRANT THE COMPANY’S REQUEST**
19 **CONCERNING LAUF GAS COSTS AND UNCOLLECTIBLES, DO YOU**
20 **BELIEVE THE COMMISSION SHOULD REDUCE THE COMPANY’S**
21 **ALLOWED RETURN ON EQUITY?**

⁷² Response to Attorney General’s Second Discovery Request to SEMCO Energy Gas Company, 2-AG-48.

⁷³ Response to Attorney General’s Second Discovery Request to SEMCO Energy Gas Company, 2-AG-49.

1 A. Yes, any such change in risk should be recognized in estimating the
2 Company's return on equity. Further, as I noted before, any shift of risk from
3 shareholders to ratepayers that has not been accompanied by a corresponding
4 adjustment in rates, cannot, by definition, result in rates that are fair, just and
5 reasonable.

6 **XII. CONCLUSIONS AND RECOMMENDATIONS**

7 **Q WOULD YOU PLEASE SUMMARIZE YOUR RECOMMENDATIONS?**

8 A. My recommendations on the Company's proposed rate re-design and
9 demand-side management programs can be summarized as follows:

- 10 • The Commission should reject the Company's proposed straight-fixed
11 variable ("SFV") rate design. The SFV proposal would result in clear
12 benefits to utility shareholders without any commiserate benefit for
13 ratepayers. The proposed rate design is inconsistent with most residential
14 rate design practices in the U.S., could result in utility inefficiencies, does
15 not promote energy efficiency, and is clearly inequitable as it has been
16 proposed.
- 17 • The Commission should completely reject the Company's proposed DSM
18 plan and its associated \$2.0 million revenue requirement. The plan
19 provides no energy savings estimates or goals and is very loosely defined.
20 Most importantly, the plan is not based upon any finding of cost-
21 effectiveness and has no accountability. Further, this DSM plan does not
22 stand as an appropriate counterbalance to the Company's SFV rate
23 design proposal.

- 1 • The Commission should reject the Company's proposal to move from a
2 30-year to 15-year weather normalization. The Company has provided no
3 compelling evidence for movement to a shorter historic period. Further,
4 movement to 15-year normalization periods is a proposal that has been
5 rejected by the Commission in the past for other utilities.
- 6 • The Commission should reject the Company's proposed annual true-up of
7 uncollectibles expense (i.e., collection of annual differences between the
8 levels included in base rates and actuals). Truing up these expenses on
9 an annual basis would result in selective ratemaking and could result in
10 inefficiencies since the incentive to hold these costs in check could be
11 reduced. Further, the Commission has rejected similar types of proposals
12 in the very recent past, and should continue to do so in this proceeding.
- 13 • The Commission should reject the Company's proposed recovery of LAUF
14 in its gas cost recovery ("GCR") rate, as well as its alternative proposal to
15 true these up on an annual basis. Collection of these costs in the GCR
16 could create inefficiencies since annual true-ups could minimize the
17 incentive to limit outstanding balances. Further, the Commission has
18 rejected similar types of proposals in the very recent past, and should
19 continue to do so in this proceeding.

20 **Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY FILED ON**
21 **NOVEMBER 11, 2006?**

22 A Yes.

ATTACHMENT 1

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EDUCATION

Ph.D., Economics, Florida State University, 1995.
M.S., Economics, Florida State University, 1992.
M.S., International Affairs, Florida State University, 1988.
B.A., History, University of West Florida, 1987.
A.A., Liberal Arts, Pensacola Junior College, 1985.

Master's Thesis: *Nuclear Power Project Disallowances: A Discrete Choice Model of Regulatory Decisions*

Ph.D. Dissertation: *An Empirical Examination of Environmental Externalities and the Least-Cost Selection of Electric Generation Facilities*

ACADEMIC APPOINTMENTS

Louisiana State University, Baton Rouge, Louisiana

Center for Energy Studies

2006-Current	Professor
2003-Current	Associate Director
2001-2006	Associate Professor
2000-2001	Research Fellow and Adjunct Assistant Professor
1999-2000	Managing Director, Distributed Energy Resources Initiative
1995-2000	Assistant Professor

E.J. Ourso College of Business Administration, Department of Economics

2006-Current	Adjunct Professor
2001-2006	Adjunct Associate Professor
1999-2000	Adjunct Assistant Professor

Florida State University, Tallahassee, Florida
Department of Economics

1995	Instructor

PROFESSIONAL EXPERIENCE

Acadian Consulting Group, Baton Rouge, Louisiana

2001-Current	Consulting Economist/Principal
1995-2000	Consulting Economist/Principal

Econ One Research, Inc., Houston, Texas

2000-2001	Senior Economist

Florida Public Service Commission, Tallahassee, Florida
Division of Communications, Policy Analysis Section

1995	Planning & Research Economist

Division of Auditing & Financial Analysis, Forecasting Section

1993	Planning & Research Economist
1992-1993	Economist

Project for an Energy Efficient Florida &
Florida Solar Energy Industries Association, Tallahassee, Florida

1994	Energy Economist

Ben Johnson Associates, Inc., Tallahassee, Florida

1991-1992	Research Associate
1989-1991	Senior Research Analyst
1988-1989	Research Analyst

GOVERNMENT APPOINTMENTS

2005.	Member, Task Force on Energy Sector Workforce and Economic Development (HCR 322).
2003-Current	Member, Energy and Basic Industries Task Force, Louisiana Economic Development Council
2001-2003	Member, Louisiana Comprehensive Energy Policy Commission.

PUBLICATIONS: BOOKS AND MONOGRAPHS

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2. *Distributed Energy Resources: A Practical Guide for Service*. (2000). With Ritchie Priddy. London: Financial Times Energy.

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5. "A is for Access: A Definitional Tour Through Today's Energy Vocabulary." (2001) *Public Resources Law Digest*. 38: 2.
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12. "A Comment on Cost Savings from Nuclear Regulatory Reform" (1997). *Southern Economic Journal*. 63:1108-1112.
13. "The Demand for Long Distance Telephone Communication: A Route-Specific Analysis of Short-Haul Service." (1996). *Studies in Economics and Finance* 17:33-45.

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1. "Technology Based Ethical Issues Surrounding the California Energy Crisis." (2002). With Robert F. Cope III and John Yeargain. *Proceedings of the Academy of Legal, Ethical, and Regulatory Issues*. September: 17-21.
2. "Electric Utility Restructuring and Strategies for the Future." (2001). With Scott W. Geiger. *Proceedings of the Southwest Academy of Management*. March.
3. "Applications for Distributed Energy Resources in Oil and Gas Production: Methods for Reducing Flare Gas Emissions and Increasing Generation Availability" (2000). With Ritchie D. Priddy. *Proceedings of the International Energy Foundation – ENERGEX 2000*. July.
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5. "New Paradigms for Power Engineering Education." (1997). With Fred I. Denny. *Proceedings of the International Association of Science and Technology for Development*. October: 499-504.
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7. "Comparing the Safety and Environmental Records of Firms Operating Offshore Platforms in the Gulf of Mexico." (1996). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, William Daniel, and Bob Baumann. *Proceedings of the American Society of Mechanical Engineers: Offshore and Arctic Operations 1996*, January.

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2. "The Role of Distributed Energy Resources in a Restructured Power Industry." (2005). In *The Future of Electric Power Deregulation*. Edited by Andrew N. Kleit. Washington, DC: Freedom Press, Forthcoming.

3. "Competitive Power Procurement An Appropriate Strategy in a Quasi-Regulated World." (2004). In *Electric and Natural Gas Business: Using New Strategies, Understanding the Issues*. With Elizabeth A. Downer. Edited by Robert Willett. Houston, TX: Financial Communications Company, 91-104.
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5. "Challenges and Opportunities for Distributed Energy Resources in the Natural Gas Industry." (2002). In *Natural Gas and Electric Industries Analysis 2001-2002*. Edited by Robert Willett. With Martin J. Collette, Ritchie D. Priddy, and Jeffrey M. Burke. Houston, TX: Financial Communications Company, 114-131.
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3. "Renewable Portfolio Standards in the Electric Power Industry." With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 54(3): 693-706.
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6. "The Nuclear Power Plant Endgame: Decommissioning and Permanent Waste Storage. (2005). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 53 (4): 981-997
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9. "The Evolving Markets for Polluting Emissions: From Sulfur Dioxide to Carbon Dioxide." (2004). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 53(2): 479-494.
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15. "Clear Skies" or Storm Clouds Ahead? The Continuing Debate over Air Pollution and Climate Change" (2003). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 51: 823-848.
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36. "Stranded Investment and Non-Utility Generation." (1999). With Michael T. Maloney. *Electricity Journal* 12: 50-61.

37. "Reliability or Profit? Why Entergy Quit the Southwest Power Pool." (1998). With Fred I. Denny. *Public Utilities Fortnightly*. February 1: 30-33.
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1. *The Importance of Energy Production and Infrastructure in Plaquemines Parish*. (2006). Report Prepared on Behalf of Project Rebuild Plaquemines.
2. *Louisiana's Oil and Gas Industry: A Study of the Recent Deterioration in State Drilling Activity*. (2005). With Kristi A.R. Darby, Jeffrey M. Burke, and Robert H. Baumann. Baton Rouge, LA: Louisiana Department of Natural Resources.
3. *Comparison of Methods for Estimating the NO_x Emission Impacts of Energy Efficiency and Renewable Energy Projects Shreveport, Louisiana Case Study*. (2005). With Adam Chambers, David Kline, Laura Vimmerstedt, Art Diem, and Dmitry Mesyanzhinov. Golden, Colorado: National Renewable Energy Laboratory.
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5. *Economic Opportunities for LNG Development in Louisiana*. (2004). With Elizabeth A. Downer and Dmitry V. Mesyanzhinov. Baton Rouge, LA: Louisiana Department of Economic Development and Greater New Orleans, Inc.
6. *Marginal Oil and Gas Production in Louisiana: An Empirical Examination of State Activities and Policy Mechanisms for Stimulating Additional Production*. (2004). With Dmitry V. Mesyanzhinov, Jeffrey M. Burke, Robert H. Baumann. Baton Rouge, LA: Louisiana Department of Natural Resources, Office of Mineral Resources.
7. *Deepwater Program: OCS-Related Infrastructure in the Gulf of Mexico Fact Book*. (2004). With Louis Berger Associates, University of New Orleans National Ports and Waterways Institute, and Research and Planning Associates. MMS Study No. 1435-01-99-CT-30955. U.S. Department of the Interior, Minerals Management Service.
8. *The Power of Generation: The Ongoing Benefits of Independent Power Development in Louisiana*. With Dmitry V. Mesyanzhinov, Jeffrey M. Burke, and Elizabeth A. Downer. Baton Rouge, LA: LSU Center for Energy Studies, 2003.
9. *Modeling the Economic Impact of Offshore Oil and Gas Activities in the Gulf of Mexico: Methods and Application*. (2003). With Williams O. Olatubi, Dmitry V. Mesyanzhinov, and Allan G. Pulsipher. Prepared by the Center for Energy Studies, Louisiana State University, Baton Rouge, LA. OCS Study MMS2000-0XX. U.S. Department of the Interior, Minerals Management Service, Gulf of Mexico OCS Region, New Orleans, LA.
10. *An Analysis of the Economic Impacts Associated with Oil and Gas Activities on State Leases*.

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11. *Alaska In-State Natural Gas Demand Study*. (2002). With Dmitry Mesyanzhinov, et.al. Anchorage, Alaska: Alaska Department of Natural Resources, Division of Oil and Gas.
 12. *Moving to the Front of the Lines: The Economic Impacts of Independent Power Plant Development in Louisiana*. (2001). With Dmitry Mesyanzhinov and Williams O. Olatubi. Baton Rouge, LA: Louisiana State University, Center for Energy Studies.
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 14. *Energy Conservation and Electric Restructuring In Louisiana*. (2000). With Dmitry Mesyanzhinov, Ritchie D. Priddy, Robert F. Cope III, and Vera Tabakova. Baton Rouge, LA: Louisiana State University, Center for Energy Studies.
 15. *Assessing the Environmental and Safety Risks of the Expanded Role of Independents in Oil and Gas E&P Operations on the U.S. Gulf of Mexico OCS*. (1996). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, William Daniel, and Bob Baumann. Baton Rouge, LA: Louisiana State University, Center for Energy Studies.
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GRANT RESEARCH

1. *Principal Investigator*. Plaquemine Parish's Role in Supporting Critical Energy Infrastructure and Production. (2006). With Seth Cureington. Plaquemines Parish Government, Office of the Parish President and Plaquemines Association of Business and Industry. Total Project: \$18,267. Status: Completed.
2. *Co-Principal Investigator*. "Gulf Coast Subsidence and Wetland Loss: A Synthesis of Recent Research. (2006). With Kristi A. R. Darby. U.S. Department of the Interior, Minerals Management Service. Total Project \$67,031 (one year). Status: Awarded, In Progress.
3. *Principal Investigator*. "The Importance of Energy Production and Infrastructure in Plaquemines Parish. (2006). Funded by Project Rebuild Plaquemines. Total Project: \$20,000. Status: Completed.
4. *Co-Principal Investigator*. "Diversifying Energy Industry Risk in the Gulf of Mexico. (2006). With Kristi A. R. Darby. U.S. Department of the Interior, Minerals Management Service. Total Project \$165,302 (two years). Status: Awarded, In Progress.
5. *Principal Investigator*. "Ultra Deepwater Road Mapping Process." (2005). With Kristi A. R. Darby, Subcontract with the Texas A&M University, Department of Petroleum Engineering. Funded by the Gas Technology Institute. Total Project Funding: \$15,000. Status: Completed.

6. *Principal Investigator*. "An Examination of the Opportunities for Drilling Incentives on State Leases." (2004). With Robert H. Baumann and Kristi A. R. Darby. Louisiana Office of Mineral Resources. Total Project Funding: \$75,000. Status: Completed.
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8. *Principal Investigator*. "Examination of the Economic Impacts Associated with Large Customer, Industrial Retail Choice." (2004). With Dmitry V. Mesyanzhinov. Louisiana Mid-Continent Oil and Gas Association. Total Project Funding: \$37,000. Status: Completed.
9. *Principal Investigator*. "Economic Opportunities from LNG Development in Louisiana." (2003). With Dmitry V. Mesyanzhinov. Metrovision/New Orleans Chamber of Commerce and the Louisiana Department of Economic Development. Total Project Funding: \$25,000. Status: Completed.
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13. *Principal Investigator*. "Cost Profiles and Cost Functions for Gulf of Mexico Oil and Gas Development Phases for Input Output Modeling." (1998). With Dmitry Mesyanzhinov and Allan G. Pulsipher. U.S. Department of Interior, Minerals Management Service. Total Project Funding: \$244,956. Status: Completed.
14. *Principal Investigator*. "An Economic Impact Analysis of OCS Activities on Coastal Louisiana." (1998). With Dmitry Mesyanzhinov and David Hughes. U.S. Department of Interior, Minerals Management Service. Total Project Funding: \$190,166. Status: Completed.
15. *Principal Investigator*. "Energy Conservation and Electric Restructuring in Louisiana." (1997). Louisiana Department of Natural Resources. Petroleum Violation Escrow Program Funds. Total Project Funding: \$43,169. Status: Completed.
16. *Principal Investigator*. "The Industrial Supply of Electricity: Commercial Generation, Self-Generation, and Industry Restructuring" (1996). With Andrew Kleit. Louisiana Energy

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ACADEMIC CONFERENCE PAPERS

1. "The Impact of Implementing a 20 Percent Renewable Portfolio Standard in New Jersey." With Seth E. Cureington. Mid-Continent Regional Science Association 37th Annual Conference, Purdue University, Lafayette, Indiana, June 9, 2006.
2. "The Impacts of Hurricane Katrina and Rita on Energy infrastructure Along the Gulf Coast." Environment Canada: 2006 Arctic and Marine Oilspill Program. Vancouver, British Columbia, Canada.
3. "Hurricanes, Energy Markets, and Energy Infrastructure in the Gulf of Mexico: Experiences and Lessons Learned." With Kristi A.R. Darby and Seth E. Cureington. 29th Annual IAEE International Conference, Potsdam, Germany, June 9, 2006.
4. "An Examination of the Opportunities for Drilling Incentives on State Leases in Louisiana." With Kristi A.R. Darby. 28th Annual IAEE International Conference, Taipei, Taiwan (June 2005).
5. "Fiscal Mechanisms for Stimulating Oil and Gas Production on Marginal Leases." With Jeffrey M. Burke. International Association of Energy Economics Annual Conference, Washington, D.C. (July, 2004).
6. "GIS and Applied Economic Analysis: The Case of Alaska Residential Natural Gas Demand." With Dmitry V. Mesyanzhinov. Presented at the Joint Meeting of the East Lakes and West Lakes Divisions of the Association of American Geographers in Kalamazoo, MI, October 16-18, 2003.
7. "Are There Any In-State Uses for Alaska Natural Gas?" (2002). With Dmitry V. Mesyanzhinov and William E. Nebesky. IAEE/USAE 22nd Annual North American Conference: "Energy Markets in Turmoil: Making Sense of It All." October 7, 2002, Vancouver, British Columbia, Canada.
8. "The Economic Impact of State Oil and Gas Leases on Louisiana." (2002). With Dmitry V. Mesyanzhinov. 2002 National IMPLAN Users' Conference. New Orleans, Louisiana, September 4-6.
9. "Moving to the Front of the Lines: The Economic Impact of Independent Power Plant Development in Louisiana." (2002). With Dmitry V. Mesyanzhinov and Williams O. Olatubi. 2002 National IMPLAN Users' Conference. New Orleans, Louisiana, September 4-6.

10. "New Consistent Approach to Modeling Regional Economic Impacts of Offshore Oil and Gas Activities in the Gulf of Mexico." (2002). With Vicki Zatarain. 2002 National IMPLAN Users' Conference. New Orleans, Louisiana, September 4-6.
11. "Distributed Energy Resources, Energy Efficiency, and Electric Power Industry Restructuring." (1999). American Society of Environmental Science Fourth Annual Conference. Baton Rouge, Louisiana. December.
12. "Estimating Efficiency Opportunities for Coal Fired Electric Power Generation: A DEA Approach." (1999). With Williams O. Olatubi. Southern Economic Association Sixty-ninth Annual Conference. New Orleans, November.
13. "Applied Approaches to Modeling Regional Power Markets." (1999.) With Robert F. Cope. Southern Economic Association Sixty-ninth Annual Conference. New Orleans, November 1999.
14. "Parametric and Non-Parametric Approaches to Measuring Efficiency Potentials in Electric Power Generation." (1999). With Williams O. Olatubi. International Atlantic Economic Society Annual Conference, Montreal, October.
15. "Asymmetric Choice and Customer Benefits: Lessons from the Natural Gas Industry." (1999). With Rachelle F. Cope and Dmitry Mesyanzhinov. International Association of Energy Economics Annual Conference. Orlando, Florida. August.
16. "Modeling Regional Power Markets and Market Power." (1999). With Robert F. Cope. Western Economic Association Annual Conference. San Diego, California. July.
17. "Economic Impact of Offshore Oil and Gas Activities on Coastal Louisiana" (1999). With Dmitry Mesyanzhinov. Annual Meeting of the Association of American Geographers. Honolulu, Hawaii. March.
18. "Empirical Issues in Electric Power Transmission and Distribution Cost Modeling." (1998). With Robert F. Cope and Dmitry Mesyanzhinov. Southern Economic Association. Sixty-Eighth Annual Conference. Baltimore, Maryland. November.
19. "Modeling Electric Power Markets in a Restructured Environment." (1998). With Robert F. Cope and Dan Rinks. International Association for Energy Economics Annual Conference. Albuquerque, New Mexico. October.
20. "Benchmarking Electric Utility Distribution Performance." (1998) With Robert F. Cope and Dmitry Mesyanzhinov. Western Economic Association, Seventy-sixth Annual Conference. Lake Tahoe, Nevada. June.
21. "Power System Operations, Control, and Environmental Protection in a Restructured Electric Power Industry." (1998). With Fred I. Denny. IEEE Large Engineering Systems Conference on Power Engineering. Nova Scotia, Canada. June.
22. "Benchmarking Electric Utility Transmission Performance." (1997). With Robert F. Cope and Dmitry Mesyanzhinov. Southern Economic Association, Sixty-seventh Annual Conference. Atlanta, Georgia. November 21-24.

23. "A Non-Linear Programming Model to Estimate Stranded Generation Investments in a Deregulated Electric Utility Industry." (1997). With Robert F. Cope and Dan Rinks. Institute for Operations Research and Management Science Annual Conference. Dallas Texas. October 26-29.
24. "New Paradigms for Power Engineering Education." (1997). With Fred I. Denny. International Association of Science and Technology for Development, High Technology in the Power Industry Conference. Orlando, Florida. October 27-30
25. "Cogeneration and Electric Power Industry Restructuring." (1997). With Andrew N. Kleit. Western Economic Association, Seventy-fifth Annual Conference. Seattle, Washington. July 9-13.
26. "The Unintended Consequences of the Public Utilities Regulatory Policies Act of 1978." (1997). National Policy History Conference on the Unintended Consequences of Policy Decisions. Bowling Green State University. Bowling Green, Ohio. June 5-7.
27. "Assessing Environmental and Safety Risks of the Expanding Role of Independents in E&P Operations on the Gulf of Mexico OCS." (1996). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, and Bob Baumann. U.S. Department of Interior, Minerals Management Service, 16th Annual Information Transfer Meeting. New Orleans, Louisiana.
28. "Empirical Modeling of the Risk of a Petroleum Spill During E&P Operations: A Case Study of the Gulf of Mexico OCS." (1996). With Omowumi Iledare, Allan Pulsipher, and Dmitry Mesyanzhinov. Southern Economic Association, Sixty-Sixth Annual Conference. Washington, D.C.
29. "Input Price Fluctuations, Total Factor Productivity, and Price Cap Regulation in the Telecommunications Industry" (1996). With Farhad Niami. Southern Economic Association, Sixty-Sixth Annual Conference. Washington, D.C.
30. "Recovery of Stranded Investments: Comparing the Electric Utility Industry to Other Recently Deregulated Industries" (1996). With Farhad Niami and Dmitry Mesyanzhinov. Southern Economic Association, Sixty-Sixth Annual Conference. Washington, D.C.
31. "Spatial Perspectives on the Forthcoming Deregulation of the U.S. Electric Utility Industry." (1996) With Dmitry Mesyanzhinov. Southwest Association of American Geographers Annual Meeting. Norman, Oklahoma.
32. "Comparing the Safety and Environmental Performance of Offshore Oil and Gas Operators." (1995). With Allan Pulsipher, Omowumi Iledare, Dmitry Mesyanzhinov, William Daniel, and Bob Baumann. U.S. Department of Interior, Minerals Management Service, 15th Annual Information Transfer Meeting. New Orleans, Louisiana.
33. "Empirical Determinants of Nuclear Power Plant Disallowances." (1995). Southern Economic Association, Sixty-Fifth Annual Conference. New Orleans, Louisiana.

34. "A Cross-Sectional Model of IntraLATA MTS Demand." (1995). Southern Economic Association, Sixty-Fifth Annual Conference. New Orleans, Louisiana.

ACADEMIC SEMINARS AND PRESENTATIONS

1. "Hurricane Impacts on Energy Production and Infrastructure." Presentation Before the 53rd Mineral Law Institute, Louisiana State University. April 7, 2006.
2. "Trends and Issues in the Natural Gas Industry and the Development of LNG: Implications for Louisiana. (2004) 51st Mineral Law Institute, Louisiana State University, Baton Rouge, LA. April 2, 2004.
3. "Electric Restructuring and Conservation." (2001). Presentation before the Department of Electrical Engineering, McNeese State University. Lake Charles, Louisiana. May 2, 2001.
4. "Electric Restructuring and the Environment." (1998). Environment 98: Science, Law, and Public Policy. Tulane University. Tulane Environmental Law Clinic. March 7, New Orleans, Louisiana.
5. "Electric Restructuring and Nuclear Power." (1997). Louisiana State University. Department of Nuclear Science. November 7, Baton Rouge, Louisiana.
6. "The Empirical Determinants of Co-generated Electricity: Implications for Electric Power Industry Restructuring." (1997). With Andrew N. Kleit. Florida State University. Department of Economics: Applied Microeconomics Workshop Series. October 17, Tallahassee, Florida.

PROFESSIONAL AND CIVIC PRESENTATIONS

1. "Recent Trends in Natural Gas Markets." (2006). National Association of Regulatory Utility Commissioners, 118th Annual Convention. Miami, FL November 14, 2006.
2. "Energy Markets: Recent Trends, Issues & Outlook." (2006). Association of Energy Service Companies (AESC) Meeting. Petroleum Club, Lafayette, LA, November 8, 2006.
3. "Energy Outlook" (2006). National Business Economics Issues Council. Quarterly Meeting, Nashville, TN, November 1-2, 2006.
4. "Global and U.S. Energy Outlook." (2006). Energy Virginia Conference. Virginia Military Institute, Lexington, VA October 17, 2006.
5. "Interdependence of Critical Energy Infrastructure Systems." (2006). Cross Border Forum on Energy Issues: Security and Assurance of North American Energy Systems. Woodrow Wilson Center for International Scholars. Washington, DC, October 13, 2006.
6. "Determining the Economic Value of Coastal Preservation and Restoration on Critical Energy Infrastructure." (2006) The Economic and Market Impacts of Coastal Restoration: America's Wetland Economic Forum II. Washington, DC September 28, 2006.

7. "Relationships between Power and Other Critical Energy Infrastructure." (2006). Rebuilding the New Orleans Region: Infrastructure Systems and Technology Innovation Forum. United Engineering Foundation. New Orleans, LA, September 24-25, 2006.
8. "Outlook, Issues, and Trends in Energy Supplies and Prices." (2006.) Presentation to the Southern States Energy Board, Associate Members Meeting. New Orleans, Louisiana. July 14, 2006.
9. "Energy Sector Outlook." (2006). Baton Rouge Country Club Meeting. Baton Rouge, Louisiana. July 11, 2006.
10. "Oil and Gas Industry Post 2005 Storm Events." (2006). American Petroleum Institute, Teche Chapter. Production, Operations, and Regulations Annual Meeting. Lafayette, Louisiana. June 29, 2006.
11. "Concentration of Energy Infrastructure in Hurricane Regions." (2006). Presentation before the National Commission on Energy Policy Forum: Ending the Stalemate on LNG Facility Siting. Washington, DC. June 21, 2006.
12. "LNG—A Premier." (2006). Presentation Given to the U.S. Department of Energy's "LNG Forums." Los Angeles, California. June 1, 2006.
13. "Regional Energy Infrastructure, Production and Outlook." (2006). Executive Briefing for Board of Directors, Louisiana Oil and Gas Plc., Enhanced Exploration, Inc. and Energy Self-Service, Inc. Covington, Louisiana, May 12, 2006.
14. "The Impacts of the Recent Hurricane Season on Energy Production and Infrastructure and Future Outlook." Presentation before the Industrial Energy Technology Conference 2006. New Orleans, Louisiana, May 9, 2006.
15. "Update on Regional Energy Infrastructure and Production." (2006). Executive Briefing for Delegation Participating in U.S. Department of Commerce Gulf Coast Business Investment Mission. Baton Rouge, Louisiana May 5, 2006.
16. "Hurricane Impacts on Energy Production and Infrastructure." (2006). Presentation before the Interstate Natural Gas Association of America Mid-Year Meeting. Hyatt Regency Hill Country. April 21, 2006.
17. "LNG—A Premier." Presentation Given to the U.S. Department of Energy's "LNG Forums." Astoria, Washington. April 28, 2006.
18. Natural Gas Market Outlook. Invited Presentation Given to the Georgia Public Service Commission and Staff. Georgia Institute of Technology, Atlanta, Georgia. March 10, 2006.
19. The Impacts of Hurricanes Katrina and Rita on Louisiana's Energy Industry. Presentation to the Louisiana Economic Development Council. Baton Rouge, Louisiana. March 8, 2006.

20. Energy Markets: Hurricane Impacts and Outlook. Presentation to the 2006 Louisiana Independent Oil and Gas Association Annual Conference. L'Auberge du Lac Resort and Casino. Lake Charles, Louisiana. March 6, 2006
21. Energy Market Outlook and Update on Hurricane Damage to Energy Infrastructure. Presentation to the Energy Council 2005 Global Energy and Environmental Issues Conference. Santa Fe, New Mexico, December 10, 2005.
22. "Putting Our Energy Infrastructure Back Together Again." Presentation Before the 117th Annual Convention of the National Association of Regulatory Utility Commissioners (NARUC). November 15, 2005. Palm Springs, CA
23. "Hurricanes and the Outlook for Energy Markets." Presentation before the Baton Rouge Rotary Club. November 9, 2005, Baton Rouge, LA.
24. "Hurricanes, Energy Supplies and Prices." Presentation before the Louisiana Department of Natural Resources and Atchafalaya Basin Committee Meeting. November 8, 2005. Baton Rouge, LA.
25. "The Impact of the Recent Hurricane's on Louisiana's Energy Industry." Presentation before the Louisiana Independent Oil and Gas Association Board of Directors Meeting. November 8, 2005. Baton Rouge, LA.
26. "The Impact of the Recent Hurricanes on Louisiana's Infrastructure and National Energy Markets." Presentation before the Baton Rouge City Club Distinguished Speaker Series. October 13, 2005. Baton Rouge, LA.
27. "The Impact of the Recent Hurricanes on Louisiana's Infrastructure and National Energy Markets." Presentation before Powering Up: A Discussion About the Future of Louisiana's Energy Industry. Special Lecture Series Sponsored by the Kean Miller Law Firm. October 13, 2005. Baton Rouge, LA.
28. "The Impact of Hurricane Katrina on Louisiana's Energy Infrastructure and National Energy Markets." Special Lecture on Hurricane Impacts, LSU Center for Energy Studies, September 29, 2005.
29. "Louisiana Power Industry Overview." Presentation before the Clean Air Interstate Rule Implementation Stakeholders Meeting. August 11, 2005. Louisiana Department of Environmental Quality.
30. "CES 2005 Legislative Support and Outlook for Energy Markets and Policy." Presentation before the LMOGA/LCA Annual Post-Session Legislative Committee Meeting. August 10-13, 2005. Perdido Key, Florida.
31. "Electric Restructuring: Past, Present, and Future." Presentation to the Southeastern Association of Tax Administrators Annual Conference. Sheraton Hotel and Conference Facility. New Orleans, LA July 12, 2005.

32. "The Outlook for Energy." Lagniappe Studies Continuing Education Course. Baton Rouge, LA. July 11, 2005.
33. "The Outlook for Energy." Sunshine Rotary Club. Baton Rouge, LA. April 27, 2005.
34. "Background and Overview of LNG Development." Energy Council Workshop on LNG/CNG. Biloxi, Ms: Beau Rivage Resort and Hotel, April 9, 2005.
35. "Natural Gas Supply, Prices, and LNG: Implications for Louisiana Industry." Cytec Corporation Community Advisory Panel. Fortier, LA January 14, 2005.
36. "The Economic Opportunities for a Limited Industrial Retail Choice Plan." Louisiana Department of Economic Development. Baton Rouge, Louisiana. November 19, 2004.
37. "Energy Issues for Industrial Customers of Gas and Power." Louisiana Association of Business and Industry, Energy Council Meeting. Baton Rouge, Louisiana. October 11, 2004.
38. "Energy Issues for Industrial Customers of Gas and Power." Annual Meeting of the Louisiana Chemical Association and the Louisiana Chemical Industry Alliance. Point Clear, Alabama. October 8, 2004.
39. "Energy Issues for Industrial Customers of Gas and Power." American Institute of Chemical Engineers – New Orleans Section. New Orleans, LA. September 22, 2004.
40. "Natural Gas Supply, Prices and LNG: Implications for Louisiana Industry." Dow Chemical Company Community Advisory Panel Meeting. Plaquemine, LA. August 9, 2004.
41. "Energy Issues for Industrial Customers of Gas and Power." Louisiana Chemical Association Post-Legislative Meeting. Springfield, LA. August 9, 2004.
42. "LNG In Louisiana." Joint Meeting of the Louisiana Economic Development Council and the Governors Cabinet Advisory Council. Baton Rouge, LA. August 5, 2004.
43. "Louisiana Energy Issues." Louisiana Mid-Continent Oil and Gas Association Post Legislative Meetings. Sandestin, Florida. July 28, 2004.
44. "The Gulf South: Economic Opportunities Related to LNG." Presentation before the Energy Council's 2004 State and Provincial Energy and Environmental Trends Conference. Point Clear, AL, June 26, 2004.
45. "Natural Gas and LNG Issues for Louisiana." Presentation before the Rhodia Community Advisory Panel. May 20, 2004, Baton Rouge, LA.
46. "The Economic Opportunities for LNG Development in Louisiana." Presentation before the Louisiana Chemical Association Plant Managers Meeting. May 27, 2004. Baton Rouge, LA.
47. "The Economic Opportunities for LNG Development in Louisiana." Presentation before the Louisiana Chemical Association/Louisiana Chemical Industry Alliance Legislative Conference. May 26, 2004. Baton Rouge, LA.

48. "The Economic Opportunities for LNG Development in Louisiana." Presentation before the Petrochemical Industry Cluster, Greater New Orleans, Inc. May 19, 2004, Destrehan, LA.
49. "Industry Development Issues for Louisiana: LNG, Retail Choice, and Energy." Presentation before the LSU Center for Energy Studies Industry Associates. May 14, 2004, Baton Rouge, LA.
50. "The Economic Opportunities for LNG Development in Louisiana." Presentation before the Board of Directors, Greater New Orleans, Inc. May 13, 2004, New Orleans, LA.
51. "Natural Gas Outlook: Trends and Issues for Louisiana." Presentation before the Louisiana Joint Agricultural Association Meetings. January 14, 2004, Hotel Acadiana, Lafayette, Louisiana.
52. "Natural Gas Outlook" Presentation before the St. James Parish Community Advisory Panel Meeting. January 7, 2004, IMC Production Facility, Convent, Louisiana.
53. "Competitive Bidding in the Electric Power Industry." Presentation before the Association of Energy Engineers. Business Energy Solutions Expo. December 11-12, 2003, New Orleans, Louisiana.
54. "Regional Transmission Organization in the South: The Demise of SeTrans" Presentation before the LSU Center for Energy Studies Industry Associates Advisory Council Meeting. December 9, 2003. Baton Rouge, Louisiana.
55. "Affordable Energy: The Key Component to a Strong Economy." Presentation before the National Association of Regulatory Utility Commissioners ("NARUC"), November 18, 2003, Atlanta, Georgia.
56. "Natural Gas Outlook." Presentation before the Louisiana Chemical Association, October 17, 2003, Pointe Clear, Alabama.
57. "Issues and Opportunities with Distributed Energy Resources." Presentation before the Louisiana Biomass Council. April 17, 2003, Baton Rouge, Louisiana.
58. "What's Happened to the Merchant Energy Industry? Issues, Challenges, and Outlook" Presentation before the LSU Center for Energy Studies Industry Associates Advisory Council Meeting. November 12, 2002. Baton Rouge, Louisiana.
59. "An Introduction to Distributed Energy Resources." Presentation before the U.S. Department of Energy, Office of Renewable Energy and Energy Efficiency, State Energy Program/Rebuild America Conference, August 1, 2002, New Orleans, Louisiana.
60. "Merchant Energy Development Issues in Louisiana." Presentation before the Program Committee of the Center for Legislative, Energy, and Environmental Research (CLEER), Energy Council. April 19, 2002.

61. "Power Plant Siting Issues in Louisiana." Presentation before 24th Annual Conference on Waste and the Environment. Sponsored by the Louisiana Department of Environmental Quality. Lafayette, Louisiana, Cajundome. March 12, 2002.
62. "Merchant Power and Deregulation: Issues and Impacts." Presentation before the Air and Waste Management Association Annual Meeting. Baton Rouge, LA, November 15, 2001.
63. "Moving to the Front of the Lines: The Economic Impact of Independent Power Production in Louisiana." Presentation before the LSU Center for Energy Studies Merchant Power Generation and Transmission Conference, Baton Rouge, LA. October 11, 2001.
64. "Economic Impacts of Merchant Power Plant Development in Mississippi." Presentation before the U.S. Oil and Gas Association Annual Oil and Gas Forum. Jackson, Mississippi. October 10, 2001.
65. "Economic Opportunities for Merchant Power Development in the South." Presentation before the Southern Governor's Association/Southern State Energy Board Meetings. Lexington, KY. September 9, 2001.
66. "The Changing Nature of the Electric Power Business in Louisiana." Presentation before the Louisiana Department of Environmental Quality. Baton Rouge, LA, August 27, 2001.
67. "Power Business in Louisiana: Background and Issues." Presentation before the Louisiana Interagency Group on Merchant Power Development. Baton Rouge, LA, July 16, 2001.
68. "The Changing Nature of the Electric Power Business in Louisiana: Background and Issues." Presentation before the Louisiana Office of the Governor. Baton Rouge, LA, July 16, 2001.
69. "The Changing Nature of the Electric Power Business in Louisiana: Background and Issues." Presentation before the Louisiana Department of Economic Development. Baton Rouge, LA, July 3, 2001.
70. "The Economic Impacts of Merchant Power Plant Development In Mississippi." Presentation before the Mississippi Public Service Commission. Jackson, Mississippi, March 20, 2001.
71. "Energy Conservation and Electric Restructuring." With Ritchie D. Priddy. Presentation before the Louisiana Department of Natural Resources. Baton Rouge, Louisiana, October 23, 2000.
72. "Pricing and Regulatory Issues Associated with Distributed Energy." Joint Conference by Econ One Research, Inc., the Louisiana State University Distributed Energy Resources Initiative, and the University of Houston Energy Institute: "Is the Window Closing for Distributed Energy?" Houston, Texas, October 13, 2000.
73. "Electric Reliability and Merchant Power Development Issues." Technical Meetings of the Louisiana Public Service Commission. Baton Rouge, LA. August 29, 2000.
74. "A Introduction to Distributed Energy Resources." Summer Meetings, Southeastern Association of Regulatory Utility Commissioners (SEARUC). New Orleans, LA. June 27, 2000.

75. Roundtable Moderator/Discussant. Mid-South Electric Reliability Summit. U.S. Department of Energy. New Orleans, Louisiana. April 24, 2000.
76. "Electricity 101: Definitions, Precedents, and Issues." Energy Council's 2000 Federal Energy and Environmental Matters Conference. Loews L'Enfant Plaza Hotel, Washington, D.C. March 11-13, 2000.
77. "LSU/CES Distributed Energy Resources Initiatives." Los Alamos National Laboratories. Office of Energy and Sustainable Systems. Los Alamos, New Mexico. February 16, 2000.
78. "Distributed Energy Resources Initiatives." Louisiana State University, Center for Energy Studies Industry Associates Meeting. Baton Rouge, Louisiana. December 15, 1999.
79. "Merchant Power Opportunities in Louisiana." Louisiana Mid-Continent Oil and Gas Association (LMOGA) Power Generation Committee Meetings. Baton Rouge, Louisiana. November 10, 1999.
80. Roundtable Discussant. "Environmental Regulation in a Restructured Market" The Big E: How to Successfully Manage the Environment in the Era of Competitive Energy. PUR Conference. New Orleans, Louisiana. May 24, 1999.
81. "The Political Economy of Electric Restructuring In the South" Southeastern Electric Exchange, Rate Section Annual Conference. New Orleans, Louisiana. May 7, 1999.
82. "The Dynamics of Electric Restructuring in Louisiana." Joint Meeting of the American Association of Energy Engineers and the International Association of Facilities Managers. Metairie, Louisiana. April 29, 1999.
83. "The Implications of Electric Restructuring on Independent Oil and Gas Operations." Petroleum Technology Transfer Council Workshop: Electrical Power Cost Reduction Methods in Oil and Gas Field Operations. Lafayette, Louisiana, March 24, 1999.
84. "What's Happened to Electricity Restructuring in Louisiana?" Louisiana State University, Center for Energy Studies Industry Associates Meeting. March 22, 1999.
85. "A Short Course on Electric Restructuring." Central Louisiana Electric Company. Sales and Marketing Division. Mandeville, Louisiana, October 22, 1998.
86. "The Implications of Electric Restructuring on Independent Oil and Gas Operations." Petroleum Technology Transfer Council Workshop: Electrical Power Cost Reduction Methods in Oil and Gas Field Operations. Shreveport, Louisiana, October 13, 1998.
87. "How Will Utility Deregulation Affect Tourism." Louisiana Travel Promotion Association Annual Meeting, Alexandria, Louisiana. January 15, 1998.
88. "Reflections and Predictions on Electric Utility Restructuring in Louisiana." With Fred I. Denny. Louisiana State University, Center for Energy Studies Industry Associates Meeting. November 20, 1997.

89. "Electric Utility Restructuring in Louisiana." Hammond Chamber of Commerce, Hammond, Louisiana. October 30, 1997.
90. "Electric Utility Restructuring." Louisiana Association of Energy Engineers. Baton Rouge, Louisiana. September 11, 1997.
91. "Electric Utility Restructuring: Issues and Trends for Louisiana." Opelousas Chamber of Commerce, Opelousas, Louisiana. June 24, 1997.
92. "The Electric Utility Restructuring Debate In Louisiana: An Overview of the Issues." Annual Conference of the Public Affairs Research Council of Louisiana. Baton Rouge, Louisiana. March 25, 1997.
93. "Electric Restructuring: Louisiana Issues and Outlook for 1997." Louisiana State University, Center for Energy Studies Industry Associates Meeting, Baton Rouge, Louisiana, January 15, 1997.
94. "Restructuring the Electric Utility Industry." Louisiana Propane Gas Association Annual Meeting, Alexandria, Louisiana, December 12, 1996.
95. "Deregulating the Electric Utility Industry." Eighth Annual Economic Development Summit, Baton Rouge, Louisiana, November 21, 1996.
96. "Electric Utility Restructuring in Louisiana." Jennings Rotary Club, Jennings, Louisiana, November 19, 1996.
97. "Electric Utility Restructuring in Louisiana." Entergy Services, Transmission and Distribution Division, Energy Centre, New Orleans, Louisiana, September 12, 1996.
98. "Electric Utility Restructuring" Louisiana Electric Cooperative Association, Baton Rouge, Louisiana, August 27, 1996.
99. "Electric Utility Restructuring -- Background and Overview." Louisiana Public Service Commission, Baton Rouge, Louisiana, August 14, 1996.
100. "Electric Utility Restructuring." Sunshine Rotary Club Meetings, Baton Rouge, Louisiana, August 8, 1996.
101. Roundtable Moderator, "Stakeholder Perspectives on Electric Utility Stranded Costs." Louisiana State University, Center for Energy Studies Seminar on Electric Utility Restructuring in Louisiana, Baton Rouge, May 29, 1996.
102. Panelist, "Deregulation and Competition." American Nuclear Society: Second Annual Joint Louisiana and Mississippi Section Meetings, Baton Rouge, Louisiana, April 20, 1996.

EXPERT WITNESS, LEGISLATIVE, AND PUBLIC TESTIMONY; EXPERT REPORTS AND AFFIDAVITS

1. Docket Number 29380, ex parte. (2006.) Before the Louisiana Public Service Commission. In

re: An Investigation Into the Ratemaking and Generation Planning Implications of the U.S. EPA Clean Air Interstate Rule. On the behalf of the Louisiana Public Service Commission Staff. Report and Recommendation. Issues: environmental regulation and cost recovery; allowance allocations and air credit markets; ratepayers impacts of new environmental regulations.

2. Affidavit Before the Louisiana Tax Commission (2006). On behalf of ANR Pipeline, Tennessee Gas Transmission and Southern Natural Gas Company. Issues: Competitive nature of interstate and intrastate transportation services.
3. Affidavit Before the 19th Judicial District Court (2006). Suit Number 491, 453 Section 26. On behalf of Transcontinental Pipeline Corporation, et.al. Issues: Competitive nature of interstate and intrastate transportation services.
4. Docket Number 05-057-T01 (2006). Before the Utah Public Service Commission. In the Matter of: Joint Application of Questar Gas Company, the Division of Public Utilities, and Utah Clean Energy for Approval of the Conservation Enabling Tariff Adjustment Options and Accounting Orders. On the behalf of the Utah Committee of Consumer Services. Issues: Revenue Decoupling, Demand-side Management; Energy Efficiency policies. (Rebuttal and Supplemental Rebuttal Testimony)
5. Testimony before the Louisiana Legislature (2006). Senate Committee on Natural Resources. Senate Bill 655 Regarding Remediation of Oil and Gas Sites, Legacy Lawsuits, and the Deterioration of State Drilling.
6. Rulemaking Docket (2005). Before the New Jersey Bureau of Public Utilities. In re: Proposed Rulemaking Changes Associated with New Jersey's Renewable Portfolio Standard. Expert Report. The Economic Impacts of New Jersey's Proposed Renewable Portfolio Standard. On behalf of the New Jersey Office of Ratepayer Advocate. Issues: Renewable Portfolio Standards, rate impacts, economic impacts, technology cost forecasts.
7. Docket Number 2005-191-E. (2005). Before the South Carolina Public Service Commission. On behalf of NewSouth Energy LLC. In re: General Investigation Examining the Development of RFP Rules for Electric Utilities. Issues: Competitive bidding; merchant development. (Direct and Rebuttal Testimony).
8. Docket No. 05-UA-323. (2005). Before the Mississippi Public Service Commission. On the behalf of Calpine Corporation. In re: Entergy Mississippi's Proposed Acquisition of the Attala Generation Facility. Issues: Asset acquisition; merchant power development; competitive bidding.
9. Docket Number 050045-EI and 050188-EI. (2005). Before the Florida Public Service Commission. On the behalf of the Citizens of the State of Florida. In re: Petition for Rate Increase by Florida Power & Light Company. Issues: Load forecasting; O&M forecasting and benchmarking; incentive returns/regulation.
10. Comments on Decreased Drilling Activities in Louisiana and the Role of Incentives. (2005). Louisiana Mineral Board Monthly Docket and Lease Sale. July 13, 2005
11. Legislative Testimony (2005). Background and Impact of LNG Facilities on Louisiana. Joint

Meeting of Senate and House Natural Resources Committee. Louisiana Legislature. May 19, 2005.

12. Docket No. U-21453. (2005). Technical Conference before the Louisiana Public Service Commission. Comments on an Investigation for a Limited Industrial Retail Choice Plan.
13. Docket No. 2003-K-1876. (2005). On Behalf of Columbia Gas Transmission. Expert Testimony on the Competitive Market Structure for Gas Transportation Service in Ohio. Before the Ohio Board of Tax Appeals.
14. Docket No. 99-4490-J, *Lafayette City-Parish Consolidated Government, et. al. v. Entergy Gulf States Utilities, Inc. et. al.* (2005, 2006). On behalf of the City of Lafayette, Louisiana and the Lafayette Utilities Services. Expert Rebuttal Report of the Harborfront Consulting Group Valuation Analysis of the LUS Expropriation. Filed before 15th Judicial District Court, Lafayette, Louisiana.
15. ANR Pipeline Company v. Louisiana Tax Commission (2005), Number 468,417 Section 22, 19th Judicial District Court, Parish of East Baton Rouge, State of Louisiana Consolidated with Docket Numbers: 480,159; 489,776; 480,160; 480,161; 480,162; 480,163; 480,373; 489,776; 489,777; 489,778; 489,779; 489,780; 489,803; 491,530; 491,744; 491,745; 491,746; 491,912; 503,466; 503,468; 503,469; 503,470; 515,414; 515,415; and 515,416. In re: Market structure issues and competitive implications of tax differentials and valuation methods in natural gas transportation markets for interstate and intrastate pipelines.
16. Docket No. U-27159. (2004). On Behalf of the Louisiana Public Service Commission Staff. Expert Report on Overcharges Assessed by Network Operator Services, Inc. Before the Louisiana Public Service Commission.
17. Docket Number 2004-178-E. (2004). Before the South Carolina Public Service Commission. On behalf of Columbia Energy LLC. In re: Rate Increase Request of South Carolina Electric and Gas. (Direct and Surrebuttal Testimony)
18. Docket Number 040001-EI. (2004). Before the Florida Public Service Commission. On behalf of Power Manufacturing Systems LLC, Thomas K. Churbuck, and the Florida Industrial Power Users Group. In re: Fuel Adjustment Proceedings; Request for Approval of New Purchase Power Agreements. Company examined: Florida Power & Light Company.
19. Docket Number 27363. (2004). Before the Public Utilities Commission of Texas. Joint Affidavit on Behalf of the Cities of Texas and the Staff of the Public Utilities Commission of Texas Regarding Certified Issues. In Re: Application of Valor Telecommunications, L.P. For Authority to Establish Extended Local Calling Service (ELCS) Surcharges For Recovery of ELCS Surcharge.
20. Expert Report and Testimony. Docket 1997-4665-PV, 1998-4206-PV, 1999-7380-PV, 2000-5958-PV, 2001-6039-PV, 2002-64680-PV, 2003-6231-PV. (2003) Before the Kansas Board of Tax Appeals. (2003). In the Matter of the Appeals of CIG Field Services Company from orders of the Division of Property Valuation. On the Behalf of CIG Field Services. Issues: the competitive nature of natural gas gathering in Kansas.

21. Docket Number U-22407. Before the Louisiana Public Service Commission (2002). On the Behalf of the Louisiana Public Service Commission Staff. Company examined: Louisiana Gas Services, Inc. Issues: Purchased Gas Acquisition audit, fuel procurement and planning practices.
22. Docket Number 000824-EI. Before the Florida Public Service Commission. (2002). On the Behalf of the Citizens of the State of Florida. Company examined: Florida Power Corporation. Issues: Load Forecasts and Billing Determinants for the Projected Test Year.
23. Louisiana Board of Commerce and Industry (2001). Testimony on the Economic Impacts of Merchant Power Generation.
24. Docket Number 24468. (2001). On the Behalf of the Texas Office of Public Utility Counsel. Public Utility Commission of Texas Staff's Petition to Determine Readiness for Retail Competition in the Portion of Texas Within the Southwest Power Pool. Company examined: AEP-SWEPCO.
25. Expert Report. (2001) On Behalf of David Liou and Pacific Richland Products, Inc. to Review Cogeneration Issues Associated with Dupont Dow Elastomers, L.L.C. (DDE) and the Dow Chemical Company (Dow).
26. Docket Number 01-1049, Docket Number 01-3001. (2001) On behalf the Nevada Office of Attorney General, Bureau of Consumer Protection. Petition of Central Telephone Company-Nevada D/b/a Sprint of Nevada and Sprint Communications L.P. for Review and Approval of Proposed Revised Performance Measures and Review and Approval of Performance Measurement Incentive Plans. Before the Public Utilities Commission of Nevada.
27. Multiple Dockets (2001). Before the Louisiana Tax Commission. On the Behalf of Louisiana Interstate Pipeline Companies. Testimony on the Competitive Nature of Natural Gas Transportation Services in Louisiana.
28. Expert Affidavit before the Federal District Court, Middle District of Louisiana (2001). Issues: Competitive Nature of the Natural Gas Transportation Market in Louisiana. On behalf of a Consortium of Interstate Natural Gas Transportation Companies.
29. Louisiana Board of Commerce and Industry (2001). Testimony on the Economic and Ratepayer Benefits of Merchant Power Generation and Issues Associated with Tax Incentives on Merchant Power Generation and Transmission.
30. Docket Number 01-1048 (2001). Before the Public Utilities Commission of Nevada. On the Behalf of the Nevada Office of the Attorney General, Bureau of Consumer Protection. Company analyzed: Nevada Bell Telephone Company. Issues: Statistical Issues Associated with Performance Incentive Plans.
31. Docket 22351 (2001). Before the Public Utility Commission of Texas. On the Behalf of the City of Amarillo. Company analyzed: Southwestern Public Service Company. Issues: Unbundled cost of service, affiliate transactions, load forecasting.
32. Docket 991779-EI (2000). Before the Florida Public Service Commission. On the Behalf of the

Citizens of the State of Florida. Companies analyzed: Florida Power & Light Company; Florida Power Corporation; Tampa Electric Company; and Gulf Power Company. Issues: Competitive Nature of Wholesale Markets, Regional Power Markets, and Regulatory Treatment of Incentive Returns on Gains from Economic Energy Sales.

33. Docket 990001-EI (1999). Before the Florida Public Service Commission. On the Behalf of the Citizens of the State of Florida. Companies analyzed: Florida Power & Light Company; Florida Power Corporation; Tampa Electric Company; and Gulf Power Company. Issues: Regulatory Treatment of Incentive Returns on Gains from Economic Energy Sales.
34. Docket 950495-WS (1996). Before the Florida Public Service Commission. On the Behalf of the Citizens of the State of Florida. Company analyzed: Southern States Utilities, Inc. Issues: Revenue Repression Adjustment, Residential and Commercial Demand for Water Service.
35. Louisiana House of Representatives, Special Subcommittee on Utility Deregulation. (1997). On Behalf of the Louisiana Public Service Commission Staff. Issue: Electric Restructuring.
36. Docket 940448-EG -- 940551-EG (1994). Before the Florida Public Service Commission. On the Behalf of the Legal Environmental Assistance Foundation. Companies analyzed: Florida Power & Light Company; Florida Power Corporation; Tampa Electric Company; and Gulf Power Company. Issues: Comparison of Forecasted Cost-Effective Conservation Potentials for Florida.
37. Docket 920260-TL, (1993). Before the Florida Public Service Commission. On the Behalf of the Florida Public Service Commission Staff. Company analyzed: BellSouth Communications, Inc. Issues: Telephone Demand Forecasts and Empirical Estimates of the Price Elasticity of Demand for Telecommunication Services.
38. Docket 920188-TL, (1992). Before the Florida Public Service Commission. On the Behalf of the Florida Public Service Commission Staff. Company analyzed: GTE-Florida. Issues: Telephone Demand Forecasts and Empirical Estimates of the Price Elasticity of Demand for Telecommunication Services.

REFEREE AND EDITORIAL APPOINTMENTS

Referee, 1995-Current, *Energy Journal*

Contributing Editor, 2000-Current, *Oil, Gas and Energy Quarterly*

Referee, 2005, *Energy Policy*

Referee, 2004, *Southern Economic Journal*

Referee, 2002, *Resource & Energy Economics*

Committee Member, IAEE/USAEE Student Paper Scholarship Award Committee, 2003

PROPOSAL TECHNICAL REVIEWER

California Energy Commission, Public Interest Energy Research (PIER) Program (1999).

PROFESSIONAL ASSOCIATIONS

American Economic Association, American Statistical Association, Econometric Society, Southern Economic Association, Western Economic Association, and the International Association of Energy

Economists.

HONORS AND AWARDS

Omicron Delta Epsilon (1992-Current)

Florida Public Service Commission, Staff Excellence Award for Assistance in the Analysis of Local Exchange Competition Legislation (1995).

Distinguished Research Award, Academy of Legal, Ethical and Regulatory Issues, Allied Academics (2002).

Interstate Oil and Gas Compact Commission (IOGCC) "Best Practice" Award for Research on the Economic Impact of Oil and Gas Activities on State Leases for the Louisiana Department of Natural Resources (2003).

Baton Rouge Business Report, Selected as "Top 40 Under 40" (2003).

National Association of Regulatory Utility Commissioners (NARUC). Best Paper Award for papers published in the *Journal of Applied Regulation*.

TEACHING EXPERIENCE

Principles of Microeconomic Theory

Principles of Macroeconomic Theory

Lecturer, Electric Power Industry Environmental Issues, Field Course on Energy and the Environment. (Dept of Environmental Studies).

Lecturer, Electric Power Industry Trends, Principles Course in Power Engineering (Dept. of Electric Engineering).

Continuing Education. Electric Power Industry Restructuring for Energy Professionals.

"The Gulf Coast Energy Situation: Outlook for Production and Consumption." Educational Course and Lecture Prepared for the Foundation for American Communications and the Society for Professional Journalists, New Orleans, LA, December 2, 2004

"The Impact of Hurricane Katrina on Louisiana's Energy Infrastructure and National Energy Markets." Educational Course and Lecture Prepared for the Foundation for American Communications and the Society for Professional Journalists, Houston, TX, September 13, 2005.

THESIS/DISSERTATIONS COMMITTEES

5 Thesis Committee Memberships (Environmental Studies, Geography)

3 Doctoral Committee Memberships (Information Systems & Decision Sciences, Agricultural and Resource Economics, Economics).

LSU SERVICE AND COMMITTEE MEMBERSHIPS

LSU Faculty Senate Committee on Public Relations (1997-1999).
LSU Faculty Senate Committee on Student Retention and Recruitment (1999-2003).
LSU CES/SCE Public Art Selection Committee (2003-2005).
LSU InterCollege Environmental Cooperative. (1999-2001).
LSU Main Campus Cogeneration/Turbine Project, (1999-2000).

Co-Chairman, Review Committee, Louisiana Port Construction and Development Priority Program Rules and Regulations, On Behalf of the LSU Ports and Waterways Institute. (1997).

Conference Coordinator. Center for Energy Studies Seminar Series on Electric Utility Restructuring and Wholesale Competition. (1996-2003).

Conference Coordinator. Center for Energy Studies Annual Energy Conference/Summit. (2003-Current).

Conference Coordinator. (2005-Current) Center for Energy Studies Conference on Alternative Energy.

LSU Faculty Senate (2003-2006)

LSU Graduate Research Faculty, Associate Member (1997-2004); Full Member (2004-Current)

Search Committee Member (2005), CES Communications Manager.

Search Committee Member (2005), Research Associate 4 Position.

Search Committee Chair (2006), Research Associate 4 Position.

Departmental Promotion Committee (2006).

PROFESSIONAL SERVICE

Committee Member (2006), IAEE Nominating Committee.

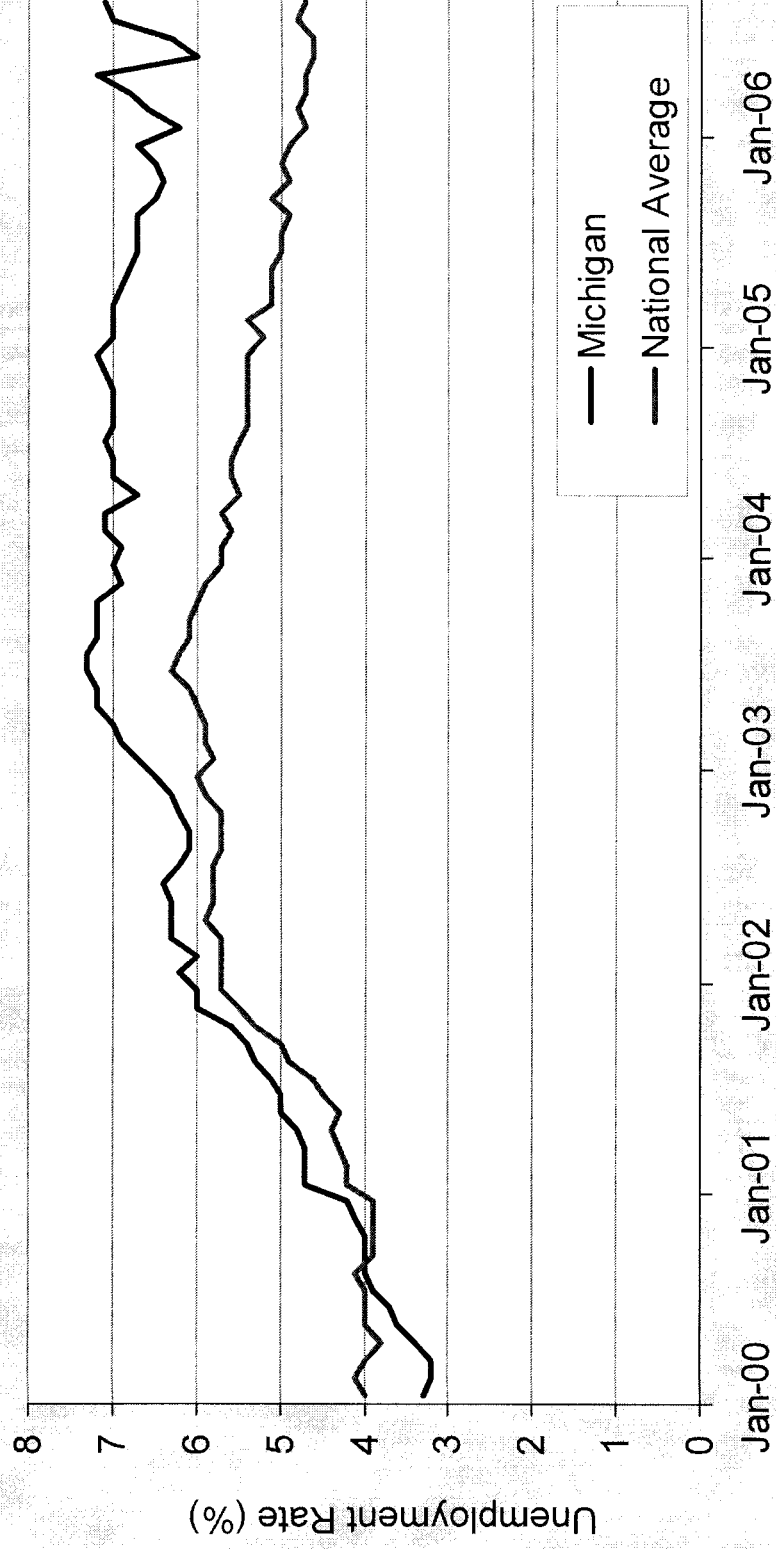
Founding President (2005) Louisiana Chapter, U.S. Association for Energy Economics

Secretary (2001) Houston Chapter, U.S. Association for Energy Economics

Advisor, Louisiana LNG Buyers/Developers Summit, Office of the Governor/Louisiana Department of Economic Development/Louisiana Department of Natural Resources, and Greater New Orleans, Inc. (2004).

Michigan Unemployment

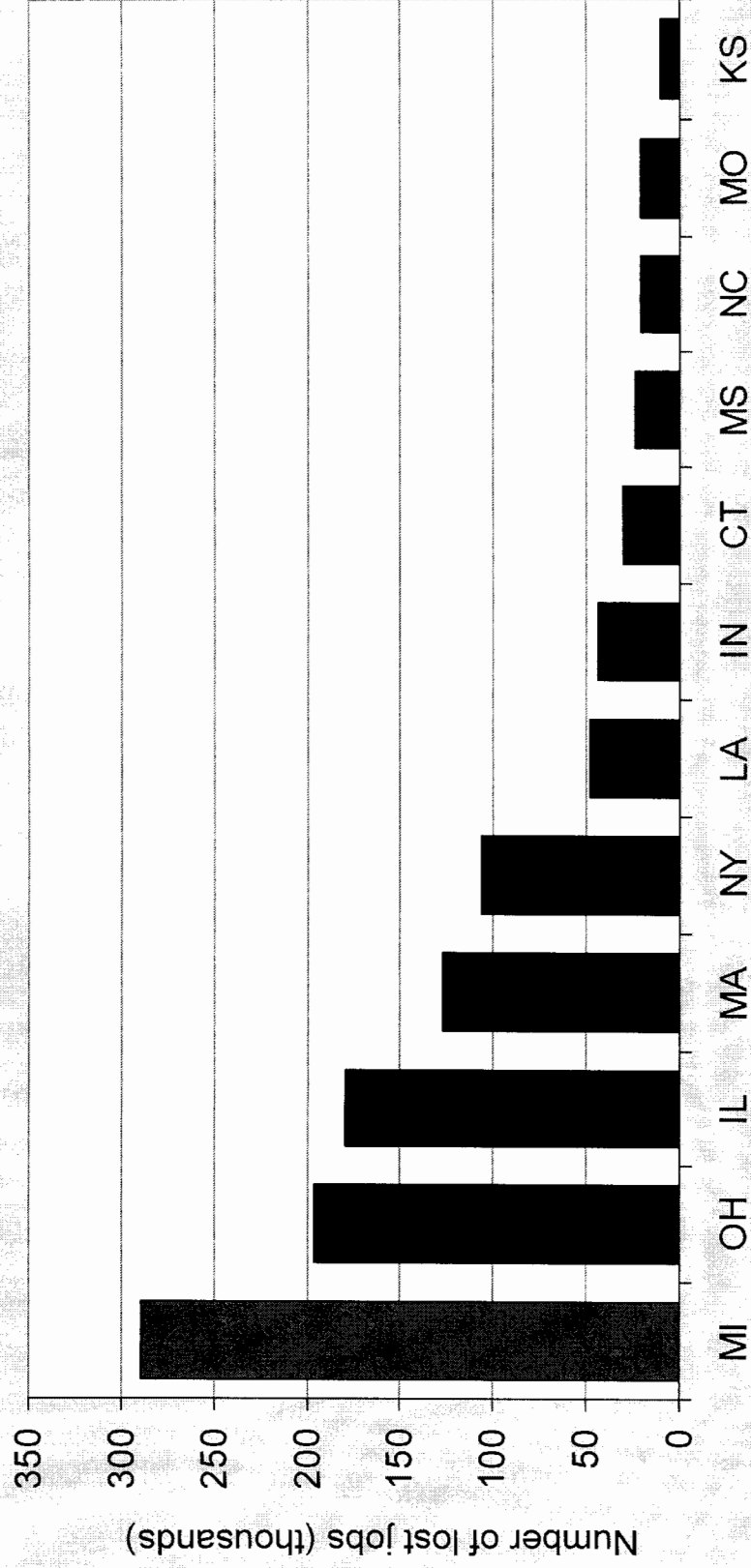
Case No.: U-14893
Witness: David E. Dismukes, Ph.D.
Exhibit: AG-1



Source: Bureau of Labor Statistics, US Department of Labor

Job Losses by State Total Since 2000

Case No.: U-14893
Witness: David E. Dismukes, Ph.D.
Exhibit: AG-2



Source: Bureau of Labor Statistics, US Department of Labor

Economic Outlook

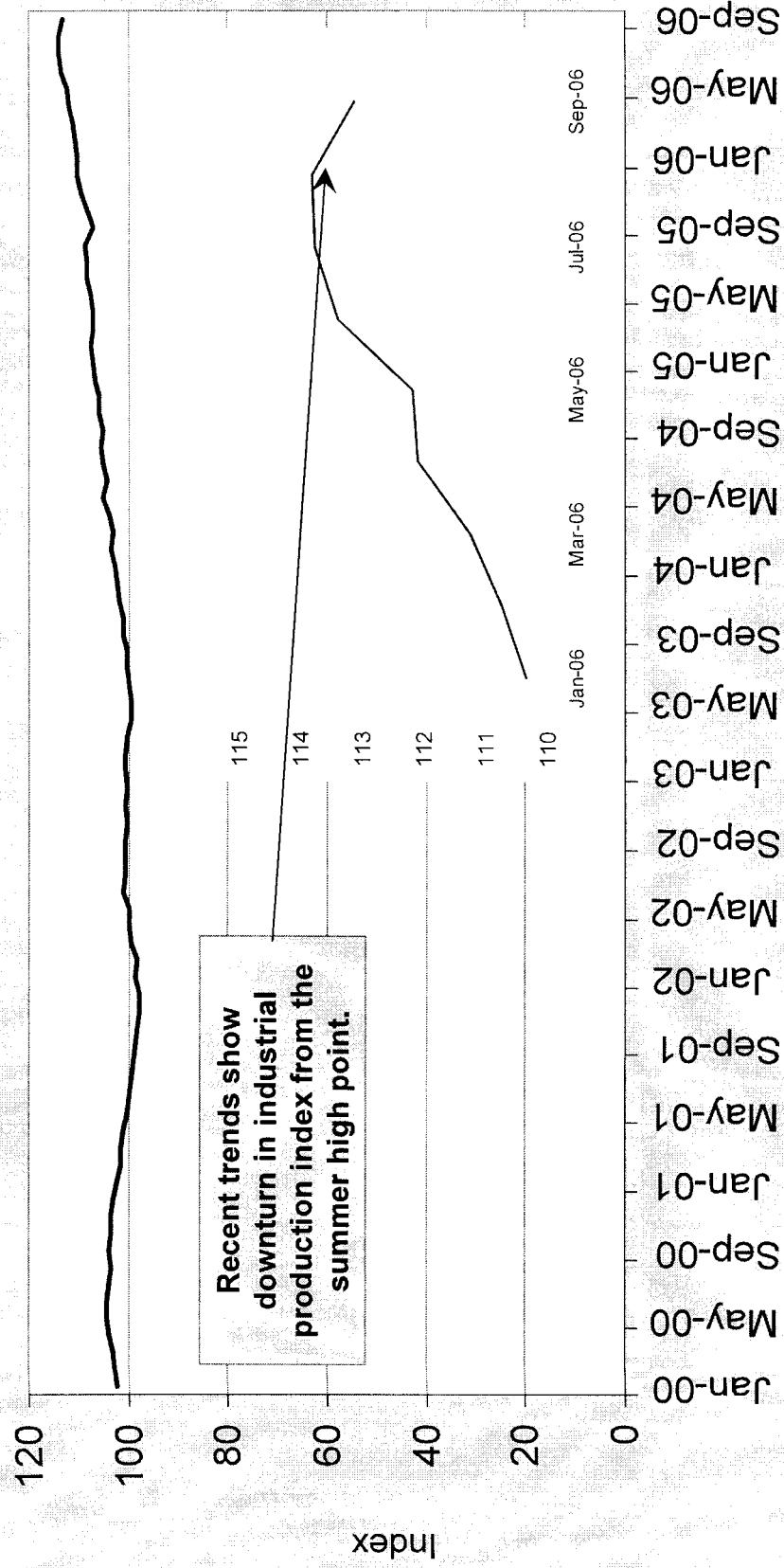
Case No.: U-14893
 Witness: David E. Dismukes, Ph.D.
 Exhibit: AG-3

	Real GDP Growth		Unemployment Rate	
	Previous	New	Previous	New
	----- (%) -----		----- (%) -----	
Quarterly data:				
2006: Q3	3.1	2.7	4.7	4.7
Q4	3.0	2.9	4.8	4.8
2007: Q1	2.9	2.9	4.8	4.8
Q2	3.0	2.7	4.8	4.9
Q3	n.a.	3.0	n.a.	4.9

Note: n.a. denotes 'not available'.
 Source: Survey of Professional Forecasters, Federal Reserve Bank of Philadelphia, August 14, 2006

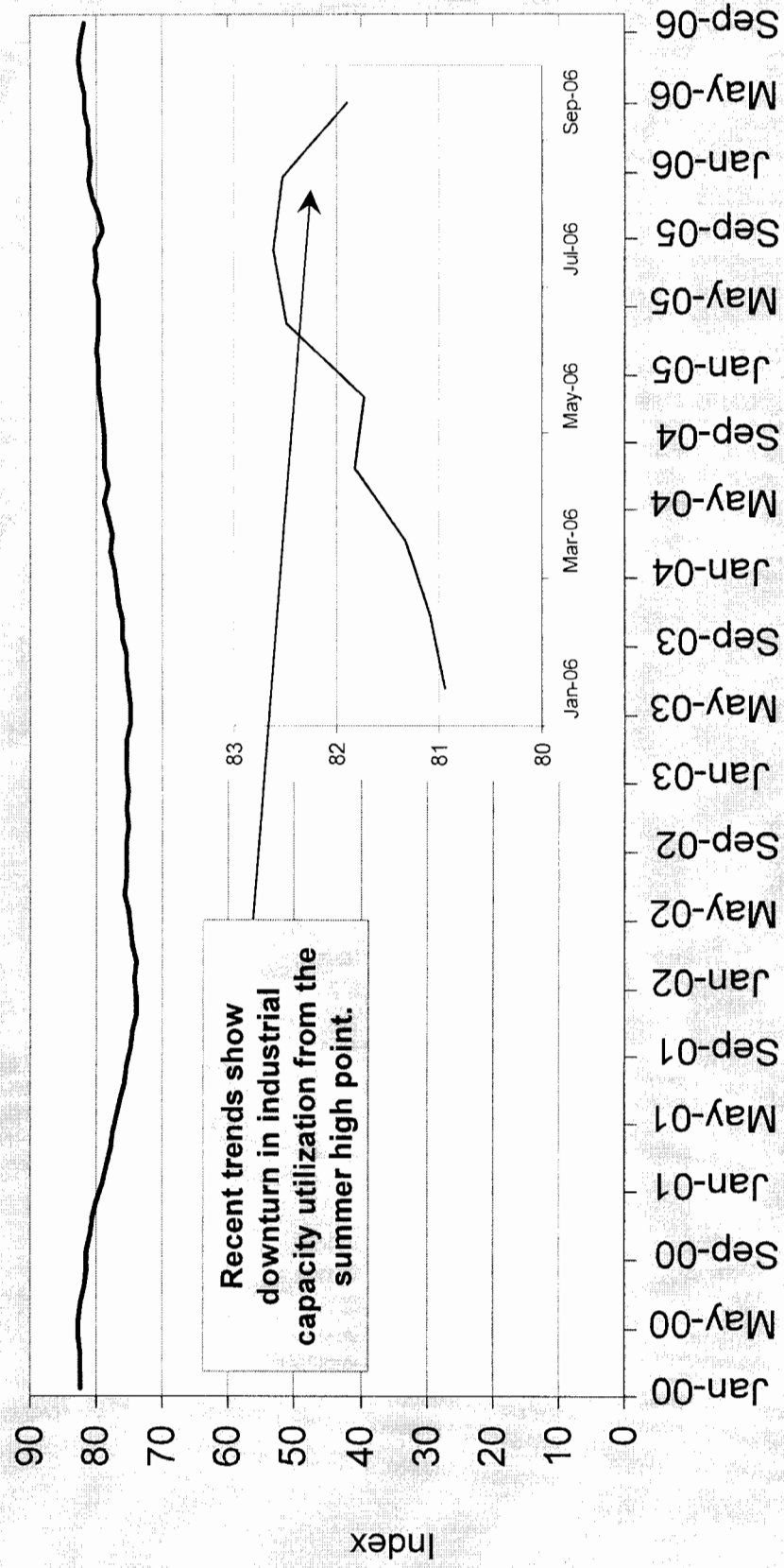
Industrial Production Index

Case No.: U-14893
Witness: David E. Dismukes, Ph.D.
Exhibit: AG-4



Manufacturing Capacity Utilization

Case No.: U-14893
Witness: David E. Dismukes, Ph.D.
Exhibit: AG-5



Source: Federal Reserve Statistical Release

Quotes from Company Application

Case No.: U-14893

Witness: David E. Dismukes, Ph.D.

Exhibit: AG-6

"The state of the economy in Michigan and the associated reduction in SEMCO Gas's customer growth ... is another risk factor." [Direct Testimony and Exhibit of Annette Gardiner, P.E., 22: 17-19]

"While the economic picture has brightened significantly since the downturn that began in 2001, uncertainties over the durability and pace of economic growth persist, especially in the industrial sections of the country (including Michigan, where SEMCO Gas operates)." [Direct Testimony and Exhibit of Bruce H. Fairchild, 27: 2-5]

"Stagnation in economic growth would undoubtedly mean flat or declining gas sales (which, as other witnesses point out, is occurring in SEMCO Gas's MPSC Division's service area), while the potential for increased inflation and interest rates places additional pressure on the adequacy of existing service rates" [Direct Testimony and Exhibit of Bruce H. Fairchild, 27-28: 17-5]

"While the economy may continue on a path of fairly steady growth and the volatility in the capital and energy markets may abate, the uncertainties now present may well persist, which increases the risks faced by the natural gas industry, including LDCs." [Direct Testimony and Exhibit of Bruce H. Fairchild, 28: 7-10]

"Also, adding new customers to the Company's system appears to be a struggle in the current Michigan economic environment and does not necessarily solve the problem." [Direct Testimony and Exhibit of Malcolm R. Ketchum, 20: 20-22]

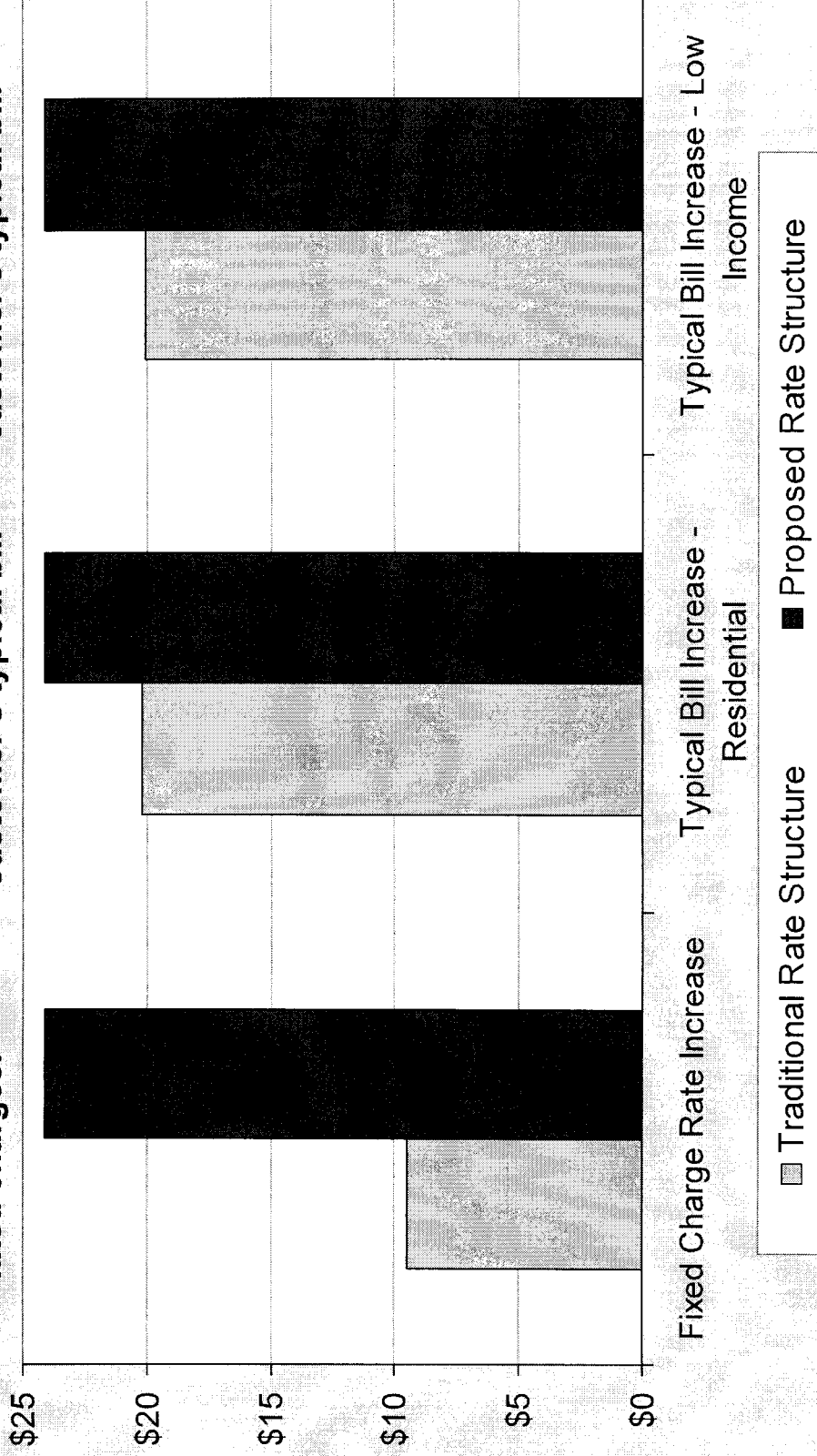
"Some of the economic factors that may affect the natural gas consumption of commercial and industrial customers include the cost of gas and the state of the economy in Michigan. These factors may reduce demand for customers' products or services, and, in turn, the gas consumed to provide those products and services." [Response to Attorney General's Second Discovery Request to SEMCO Energy Gas Company, 2-AG-71]

Customer Impacts of SEMCO's Proposed Rate Changes

Case No.: U-14893
 Witness: David E. Dismukes, Ph.D.
 Exhibit: AG-7

SEMCO's proposed rate structure represents:

a 154 percent increase in a residential customer's typical bill*
 a 19 percent increase in a residential customer's typical bill*
 a 20 percent increase in a low-income customer's typical bill**



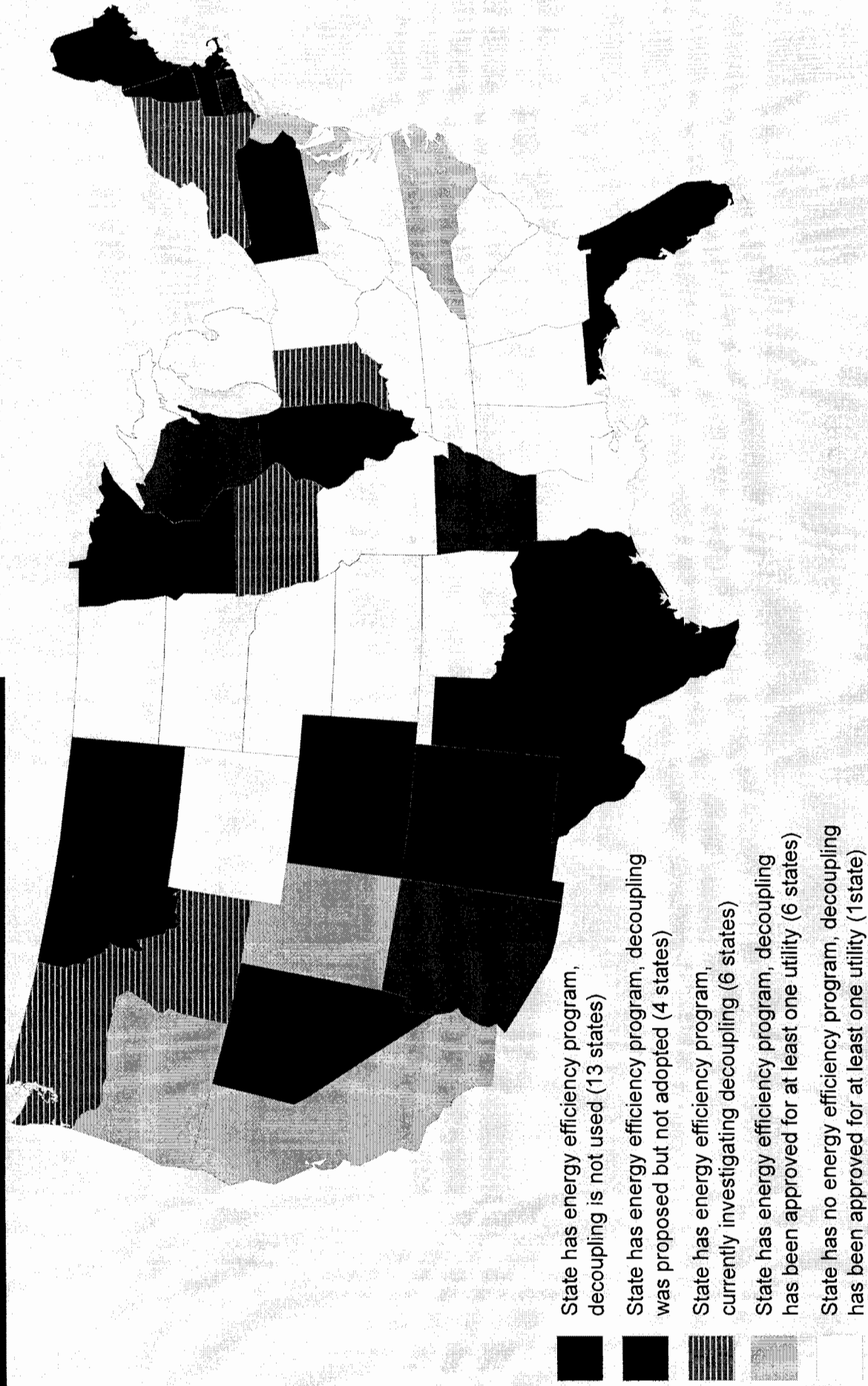
Note: *Assumes typical usage of 105.343 Mcf/year or 8.78 Mcf/month; **Assumes typical usage of 103.45 Mcf/year or 8.62 Mcf/month; slide represents changes in typical distribution service bill (non-fuel portion of bill); and calculations do not include LAUF charges.

States with Energy Efficiency Programs – Decoupling Status

Case No.: U-14893

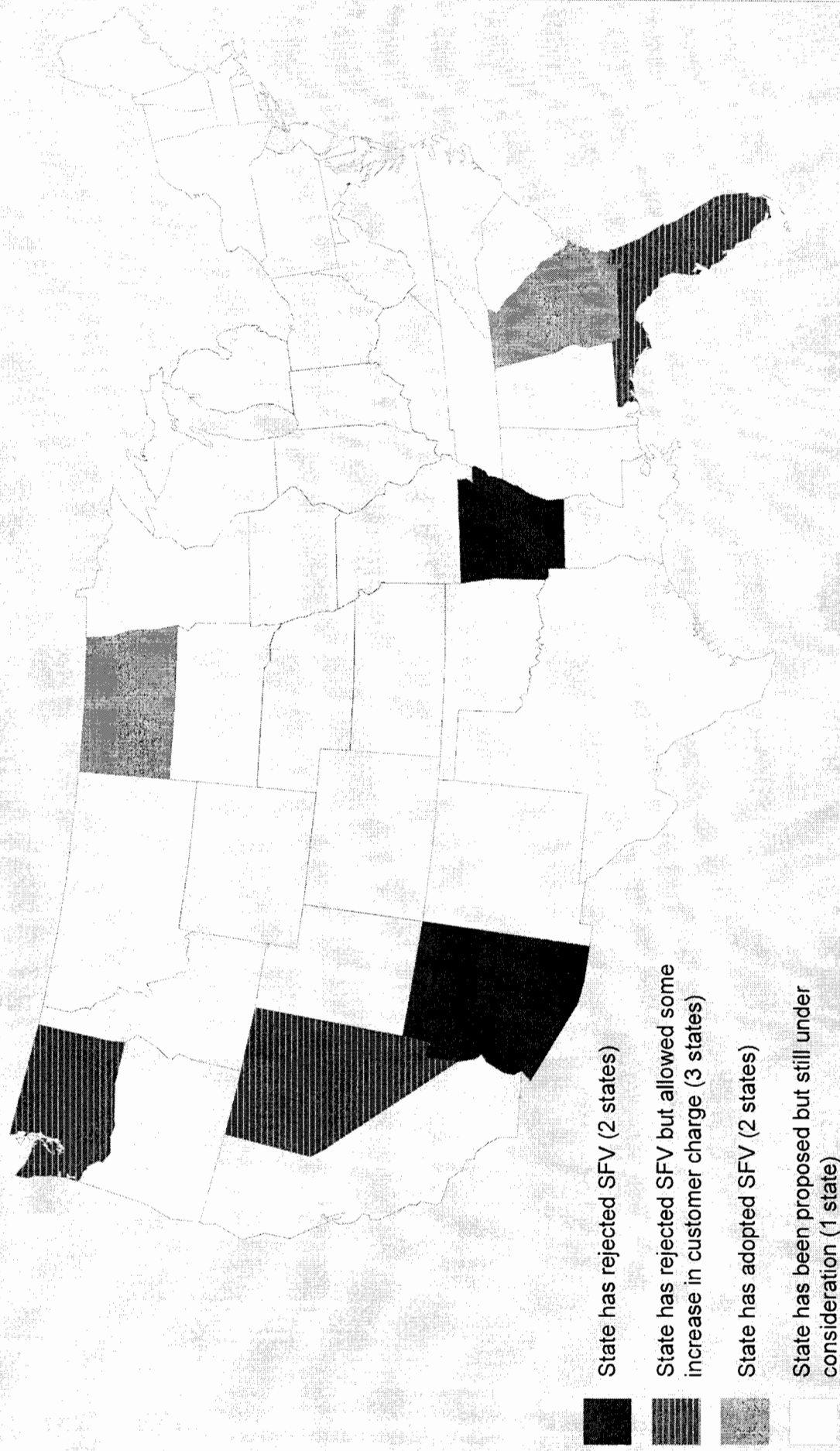
Witness: David E. Dismukes, Ph.D.

Exhibit: AG-8



States That Have Considered SFV

Case No.: U-14893
Witness: David E. Dismukes, Ph.D.
Exhibit: AG-9



Information on Comprehensive DSM Programs Implemented by Ten Gas Utilities in 2004

Case No.: U-14893

Witness: David E. Dismukes, Ph.D.

Exhibit: AG-10

	Program Spending (million \$)	Percent of Retail Revenues (%)	Gas Savings (Mcf/year)	Percent of Gas Sales Saved (%)	Volume saved per million \$ (Mcf/year)	Benefit-Cost Ratio
Aquila	\$ 2.10	1.4%	146,000	0.5%	69,000	-
Centerpoint	\$ 5.60	0.5%	720,000	0.5%	128,600	2.60
Keyspan	\$ 12.00	1.0%	490,000	0.4%	41,000	3.00
Northwest Natural Gas	\$ 4.70	0.7%	85,000	0.1%	18,000	-
NSTAR	\$ 3.90	0.8%	71,500	0.2%	18,000	2.29
PG&E	\$ 13.50	0.4%	2,000,000	0.7%	148,000	2.10
PSE	\$ 3.80	0.4%	311,000	0.5%	82,275	1.93
SoCal Gas	\$ 21.00	0.6%	1,100,000	0.3%	52,000	2.67
Vermont Gas	\$ 1.10	1.6%	57,000	1.0%	52,000	5.60
Xcel Energy (MN)	\$ 4.00	0.7%	663,000	0.9%	166,000	1.56

Source: S. Tegen and H. Geller, Natural Gas Demand-Side Management Programs: A National Survey. Boulder, CO: Southwest Energy Efficiency Project. January 2006.

SEMCO Energy Gas Company Energy Efficiency Proposal

Case No.: U-14893
Witness: David E. Dismukes, Ph.D.
Exhibit: AG-11

DSM Program Area	Proposed Program Costs (\$)	Proposed Program Participants	Costs as Share of Total Program	Participants as Share of Total Program	Costs as Share of Total Residential Revenues	Participants as Share of Total Residential Customers
Education Campaign	\$ 225,000		--	--	0.1%	--
Bill Insert	\$ 60,000	4	--	--	0.0%	--
Mass Media - Newspaper	\$ 30,000	2	--	--	0.0%	--
Mass Media - Radio	\$ 40,000	1	--	--	0.0%	--
Customer Forum	\$ 25,000	5	--	--	0.0%	--
Information Exhibit	\$ 50,000	1	--	--	0.0%	--
Speakers Bureau	\$ -		--	--	0.0%	--
Website	\$ 20,000	1	--	--	0.0%	--
Analysis	\$ 160,000	5,700	10.8%	49.6%	0.1%	2.6%
DIY Audit	\$ 50,000	5,000	3.4%	43.5%	0.0%	2.3%
Program Manager	\$ 10,000		0.7%	0.0%	0.0%	0.0%
Program Development & Maintenance	\$ 40,000		2.7%	0.0%	0.0%	0.0%
Professional Audit	\$ 60,000	200	4.1%	1.7%	0.0%	0.1%
Bill Analysis	\$ -	500	0.0%	4.3%	0.0%	0.2%
Measures	\$ 470,000	5,800	31.8%	50.4%	0.2%	2.6%
Appliances	\$ 80,000	400	5.4%	3.5%	0.0%	0.2%
Water Heater	\$ 20,000	400	1.4%	3.5%	0.0%	0.2%
Envelope - Simple Measures	\$ 240,000	3,000	16.2%	26.1%	0.1%	1.4%
Envelope - Other Measures	\$ 80,000	1,000	5.4%	8.7%	0.0%	0.5%
Water Consumption	\$ 50,000	1,000	3.4%	8.7%	0.0%	0.5%
Tracking	\$ 625,000	250,000	42.2%	--	0.3%	112.6%
Efficiency Report	\$ 625,000	250,000	42.2%	--	0.3%	112.6%
Program Total	\$ 1,480,000	--	--	--	0.6%	
Program Total (without Tracking)	\$ 855,000				0.3%	

Notes: "--" denotes that the calculation is not relevant.
Number of customers is based on 2005 average number of customers per month.

SEMCO Energy Gas Company Use per Customer

Case No.: U-14893
Witness: David E. Dismukes, Ph.D.
Exhibit: AG-12

Year	Residential Space Heating			Total Customers		
	30-Year Normalized	Percent Change	15-Year Normalized	15-Year Normalized	Percent Change	Percent Change
1996	123.9		124.9	N/A		
1997	122.1	-1.4%	120.1	N/A	-3.8%	
1998	114.2	-6.5%	112.5	153.6	-6.4%	0.5%
1999	115.6	1.2%	113.9	154.3	1.3%	7.2%
2000	118.1	2.2%	116.3	165.4	2.2%	-2.9%
2001	111.5	-5.6%	109.8	160.5	-5.6%	-1.4%
2002	113.7	1.9%	111.8	158.3	1.8%	-2.6%
2003	111.8	-1.6%	110.0	154.2	-1.5%	-4.5%
2004	106.6	-4.7%	104.9	147.3	-4.6%	-2.7%
2005	104.6	-1.8%	103.1	143.4	-1.8%	
7-Year Average	112.0	-1.2%	110.3	154.6	-1.2%	-0.9%
5-Year Average	109.6	-2.4%	107.9	152.8	-2.4%	-2.8%
3-Year Average	107.7	-2.3%	106.0	148.3	-2.3%	-2.7%

Source: Response to Attorney General's Second Discovery Request to SEMCO Energy Gas Company, 2-AG-58; and Response to Attorney General's Fifth Discovery Request to SEMCO Energy Gas Company, 5-AG-112.

SEMCO Energy Gas Company Number of Customers

Case No.: U-14893
Witness: David E. Dismukes, Ph.D.
Exhibit: AG-13

Year	Residential Space Heating		Total Customers	
	12-Month Average	Percent Change	12-Month Average	Percent Change
1996	172,272			
1997	179,206	4.0%		
1998	185,468	3.5%	212,229	2.9%
1999	191,163	3.1%	218,351	3.1%
2000	197,447	3.3%	225,123	2.5%
2001	202,845	2.7%	230,732	2.1%
2002	207,475	2.3%	235,567	1.7%
2003	211,196	1.8%	239,481	1.5%
2004	214,630	1.6%	243,081	1.4%
2005	218,151	1.6%	246,588	
7-Year Average	203,547	2.3%	231,394	2.2%
5-Year Average	210,859	2.0%	239,090	1.8%
3-Year Average	214,659	1.7%	243,050	1.5%

Source: Response to Attorney General's Second Discovery Request to SEMCO Energy Gas Company, 2-AG-58; and Response to Attorney General's Fifth Discovery Request to SEMCO Energy Gas Company, 5-AG-112.

SEMCO Energy Gas Company MPSC Division Historical Return Comparison

Case No.: U-14893
Witness: David E. Dismukes, Ph.D.
Exhibit: AG-14
Page 1 of 2

	2000	2001	2002	2003	2004	2005
OPERATING REVENUE:						
Gas Sales Revenue:						
Residential	\$927,074	\$739,406	\$929,344	\$1,279,652	\$1,488,572	\$1,755,981
Residential Heat	112,385,566	108,642,879	130,397,952	191,246,885	199,780,667	243,646,049
Commercial	1,425,895	1,413,712	1,942,443	1,611,902	4,143,016	4,178,597
Commercial Heat	40,093,998	45,909,093	55,435,249	81,868,019	87,372,456	107,877,705
Industrial	10,751,729	13,911,674	14,915,198	11,824,851	14,290,306	16,085,583
Other	-	-	-	12,958	-	-
Total Gas Sales Revenue	\$165,584,262	\$170,616,764	\$203,620,186	\$287,844,267	\$307,075,017	\$373,543,915
Cost of Gas Sold	106,559,858	112,586,595	142,666,110	223,153,751	245,191,438	307,820,751
Gross Margin	\$59,024,404	\$58,030,169	\$60,954,076	\$64,690,516	\$61,883,579	\$65,723,164
Other Operating Revenue:						
Total Other Operating Revenue	\$16,164,319	\$11,282,377	\$11,543,922	\$12,134,523	\$12,874,463	\$14,223,536
Total Operating Revenue	\$75,188,723	\$69,312,546	\$72,497,998	\$76,825,039	\$74,758,042	\$79,946,700
OPERATING EXPENSES:						
Operations and Maintenance	\$24,565,289	\$26,468,019	\$25,723,542	\$31,007,070	\$31,250,649	\$34,107,873
Depreciation and Amortization	11,308,946	11,784,247	12,805,512	12,620,604	12,473,554	12,955,373
Income Taxes	8,793,126	5,361,422	6,907,065	6,201,963	4,601,918	4,328,970
Income Taxes	8,711,875	5,509,253	6,722,847	6,239,158	4,602,913	4,151,825
Property and Other Taxes	4,785,803	5,937,289	6,195,887	6,502,764	7,805,413	7,433,970
Total Operating Expenses	\$49,371,913	\$49,698,808	\$51,447,788	\$56,369,599	\$56,132,529	\$58,649,041
OPERATING INCOME (LOSS)	\$25,816,810	\$19,613,738	\$21,050,210	\$20,455,440	\$18,625,513	\$21,297,659
Partial Year Rate Adjustments						\$2,301,966
ADJUSTED OPERATING INCOME	\$25,816,810	\$19,613,738	\$21,050,210	\$20,455,440	\$18,625,513	\$23,599,625
INCOME DEDUCTIONS:						
Interest Expense	\$8,922,817	\$7,591,108	\$7,190,540	\$7,934,553	\$8,809,884	\$12,125,717
ADJUSTED NET INCOME (LOSS)	\$16,893,993	\$12,022,630	\$13,859,670	\$12,520,887	\$9,815,629	\$11,473,908

SEMCO Energy Gas Company MPSC Division Historical Return Comparison

Case No.: U-14893
Witness: David E. Dismukes, Ph.D.
Exhibit: AG-14
Page 2 of 2

	2000	2001	2002	2003	2004	2005
RATE BASE (13-Month Average)						
Net Property	\$ 211,512,785	\$ 226,222,454	\$ 235,260,178	\$ 235,577,731	\$ 239,074,055	\$ 244,264,814
Peninsular Gas Net Property						789,320
Plus: Working Capital	32,576,903	24,183,285	25,216,029	60,739,085	71,234,773	73,572,081
Less: Deferred Taxes & Other	(13,751,478)	(13,892,615)	(13,437,097)	(17,087,879)	(18,314,896)	(17,418,130)
Estimated Rate Base	\$ 230,338,211	\$ 236,513,123	\$ 247,039,109	\$ 279,228,936	\$ 291,993,933	\$ 301,208,085
Company Common Equity	\$ 123,055,689	\$ 136,338,154	\$ 137,031,613	\$ 147,269,790	\$ 157,474,104	\$ 142,554,824
Common Equity Based on Industry Ratio	\$ 113,096,061	\$ 116,127,943	\$ 121,296,203	\$ 145,478,276	\$ 158,552,705	\$ 140,242,484
Company Calculated Achieved ROE	13.73%	8.82%	10.11%	8.50%	6.23%	6.43%
Attorney General Calculated Achieved ROE	14.94%	10.35%	11.43%	8.61%	6.19%	8.18%
Allowed Return on Equity	10.75%	10.75%	10.75%	11.40%	11.40%	11.00%
Company Calculated Achieved ROR	10.92%	8.06%	8.35%	7.19%	6.26%	6.96%
Attorney General Calculated Achieved ROR	11.21%	8.29%	8.52%	7.33%	6.38%	7.83%
Allowed Return on Rate Base	8.59%	8.59%	8.59%	N/A	N/A	7.49%

Source: Direct Testimony and Exhibit of Bruce H. Farchild; Response to Attorney General's Fifth Discovery Request to SEMCO Energy Gas Company, 5-AG-112 and 5-AG-115; Response to Attorney General's Second Discovery Request to SEMCO Energy Gas Company, 2-AG-36; and Company Revised Exhibits A-9, Schedules C-2 and C-10.

SEMCO Energy Gas Company **Costs per Customer**

Case No.: U-14893
 Witness: David E. Dismukes, Ph.D.
 Exhibit: AG-15

	2000	2001	2002	2003	2004	2005
Average Customers	225,123	230,732	235,567	239,481	243,081	246,588
Revenue Per Customer	\$ 736	\$ 739	\$ 864	\$ 1,202	\$ 1,263	\$ 1,515
Gross Margin Per Customer	\$ 262	\$ 252	\$ 259	\$ 270	\$ 255	\$ 267
Operating Expenses Per Customer	\$ 109	\$ 115	\$ 109	\$ 129	\$ 129	\$ 138
Rate Base Per Customer	\$ 1,023	\$ 1,025	\$ 1,049	\$ 1,166	\$ 1,201	\$ 1,222

Source: Direct Testimony and Exhibit of Bruce H. Farchild; Response to Attorney General's Fifth Discovery Request to SEMCO Energy Gas Company, 5-AG-112 and 5-AG-115; Response to Attorney General's Second Discovery Request to SEMCO Energy Gas Company, 2-AG-36; and Company Revised Exhibits A-9, Schedules C-2 and C-10.

SEMCO Energy Gas Company **LAUF Gas Volumes**

Case No.: U-14893
 Witness: David E. Dismukes, Ph.D.
 Exhibit: AG-16

	2000-2001	2001-2002	2002-2003	2003-2004	2004-2005	Five Year Total	Five Year Average
	----- (Mcf) -----						
September	43,230	60,038	19,761	34,675	24,429	182,133	36,427
October	(11,870)	82,500	53,405	56,678	44,376	225,089	45,018
November	16,128	106,594	61,803	54,929	42,490	281,944	56,389
December	121,102	97,060	48,232	(153,095)	65,542	178,841	35,768
January	92,478	78,475	91,216	110,819	75,011	447,999	89,600
February	88,561	70,589	86,022	73,418	61,926	380,516	76,103
March	77,607	73,733	70,209	64,285	57,141	342,975	68,595
April	45,556	37,604	46,959	41,485	31,053	202,657	40,531
May	27,869	35,108	30,662	26,485	23,738	143,862	28,772
June	22,667	20,403	(33,894)	0	14,079	23,255	4,651
July	25,997	17,292	(35,307)	(45,000)	12,986	(24,032)	(4,806)
August	30,000	19,541	60,123	28,980	14,364	153,008	30,602
Total LAUF	579,325	698,937	499,191	293,659	467,135	2,538,247	507,649
Total Throughput	51,553,414	47,775,498	53,429,505	49,611,308	48,366,457	250,736,182	50,147,236
% of Throughput	1.124%	1.463%	0.934%	0.592%	0.966%	1.012%	1.012%

Source: Company Revised Exhibit A--9 Schedule C-5.

SEMCO Energy Gas Company **Revenues, Gas Costs and Uncollectibles, 2000-2005**

Case No.: U-14893
 Witness: David E. Dismukes, Ph.D.
 Exhibit: AG-17

	2000	2001	2002	2003	2004	2005
Total Operating Revenues	\$ 181,748,581	\$ 181,899,135	\$ 215,164,107	\$ 299,978,790	\$ 319,949,480	\$ 387,767,450
Cost of Gas Sold	\$ 106,559,858	\$ 112,586,597	\$ 142,666,110	\$ 223,153,751	\$ 245,191,438	\$ 307,820,751
Uncollectible Expense	573,392	\$ 692,650	\$ 718,150	\$ 2,277,125	\$ 1,408,793	\$ 1,587,080
Average Number of Customers	225,123	230,732	235,567	239,481	243,081	246,588
Uncollectible Expense as Percent of Revenue	0.315%	0.381%	0.334%	0.759%	0.440%	0.409%
Uncollectible Expense as Percent of Gas Cost	0.538%	0.615%	0.503%	1.020%	0.575%	0.516%
Uncollectible Expense per Customer	\$ 2.55	\$ 3.00	\$ 3.05	\$ 9.51	\$ 5.80 ⁽¹⁾	\$ 6.44
Annual Percentage Change		17.9%	1.6%	211.9%	-39.0%	11.1%
Cost of Gas Sold per Customer	\$ 473	\$ 488	\$ 606	\$ 932	\$ 1,009	\$ 1,248
Annual Percentage Change		3.1%	24.1%	53.9%	8.2%	23.8%

Note: (1) Difference from \$5.89 reported by SEMCO in Application due to difference in number of customers.

Source: Exhibit A-1 Schedule A-3; Response to Attorney General's Second Discovery Request to SEMCO Energy Gas Company 2-AG-58; and Attorney General's Fifth Discovery Request to SEMCO Energy Gas Company 5-AG-112, 5-AG-126, and 5-AG-127.