

BEFORE THE
NEBRASKA PUBLIC SERVICE COMMISSION

In the Matter of Aquila, Inc., dba Aquila)
Networks (“Aquila”), Omaha, seeking)
individual general rate increases for Aquila’s)
Rate Area One, Rate Area Two and Rate)
Area Three)

Docket No. NG-0041

PRE-FILED DIRECT TESTIMONY OF

WILLIAM L. GLAHN

(PUBLIC VERSION)

ON BEHALF OF

PUBLIC ADVOCATE

MARCH 16, 2007

I. STATEMENT OF QUALIFICATIONS

Q. Would you please state your name, address, and occupation?

A. My name is William L. Glahn. My business address is Suite 300, 200 South Sixth Street, Minneapolis, Minnesota. I am a principal and shareholder of Dahlen, Berg Consulting, Inc., a management consulting firm specializing in energy-related services.

Q. Please describe your utility background and experience.

A. Since joining Dahlen, Berg & Co. in 1995, I have participated in many engagements related to utility cost of capital, utility rate design, financial modeling of capital projects, and utility cost analysis. In these engagements, I have, among other responsibilities, estimated a utility's cost of capital, helped create financial models for capital investment decisions, projected commodity and operating costs over the life of capital projects, and projected utility customer usages, costs, and revenue requirements. My detailed resume is included as Exhibit___(WLG-D), Schedule 1.

Q. Would you outline your educational background?

A. In 1995, I received a Master of Business Administration degree with emphasis in finance from the Colgate Darden Graduate School of Business Administration at the University of Virginia, Charlottesville, Virginia. In 1989, I received a Bachelor of Arts degree in Economics from the University of Virginia.

1 **Q. Please describe your professional background.**

2 A. From 1989 through 1994, I held research- and analysis-related positions of increasing
3 responsibility within the Federal Reserve System. In July 1995, I joined the management
4 consulting firm of Dahlen, Berg & Co. as a consultant.

II. PURPOSE OF TESTIMONY

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to present to the Nebraska Public Service Commission the results of my analysis of Aquila Inc.'s Application seeking general rate increases in Rate Areas One, Two, and Three (NG-0041). Specifically, I will address the following areas:

- Return on Equity, Cost of Debt, and Cost of Capital
- Adjustments to the Test Year
- Lead-Lag Studies and Cash Working Capital Requirements
- Weather Normalization Adjustment (WNA)
- Revenue Normalization Adjustment (RNA)
- Limited Cost Recovery
- Energy Efficiency Programs

Q. By whom were you engaged in this case?

A. Dahlen, Berg & Co. was engaged by the Public Advocate.

Q. What is the scope of the work you performed in this proceeding?

A. The scope of my work was limited to reviewing Aquila's filing, testimony, exhibits, and responses to data requests. I performed analyses of information related to Aquila's cost of service and cost of capital. I also performed analyses of information related to other natural gas utilities, including estimating Aquila's cost of equity capital by comparing it with that of similar utilities.

In the course of our review of Aquila's filing, the Public Advocate issued 157 data requests and 4 audit requests. A number of these information requests, along with Aquila's answers, are included as exhibits to my testimony.

1 **Q. Did you visit Aquila's headquarters?**

2 A. Yes. Along with my colleague, James D. Larson, I examined certain Aquila records at
3 the headquarters of the company's natural gas business in Omaha, Nebraska. Our visit
4 occurred during the days of February 26 and 27, 2007.

5 The purpose of our visit was to follow up on Public Advocate Data Requests Nos.
6 PA-7, PA-8, PA-19, and PA-87. In their responses to these Data Requests,¹ Aquila
7 indicated that the requested documents could only be examined at their offices.

8 **Q. Has Aquila made any announcements concerning the future of its natural gas**
9 **distribution business?**

10 A. Yes. On February 7, 2007, Aquila, Inc. issued an announcement² regarding its future.
11 The company announced that it was selling its natural gas distribution utilities in
12 Colorado, Kansas, Iowa, and Nebraska to Black Hills Corporation of Rapid City, South
13 Dakota. Aquila also announced that it was selling its electric utility in Colorado to Black
14 Hills. In addition, Aquila announced that it would sell its remaining businesses—
15 including its electric utility in Missouri—to Great Plains Energy of Kansas City,
16 Missouri.

17 These transactions are subject to the approvals of shareholders and of the
18 regulators in the various states. The transactions are expected to close in about a year.³

¹ Public Advocate Data Requests PA-7, PA-8, and PA-19 and Aquila's responses are included with this testimony as Exhibit__(WLG-D), Confidential Schedule 2. Data Request PA-87 and Aquila's response are included with this testimony as Exhibit__(WLG-D), Schedule 3.

² The Black Hills press release is included as Exhibit__(WLG-D), Schedule 4.

³ See Black Hills press release, page 1.

March 16, 2007

1 **Q. What role would the Commission have in this transaction?**

2 A. In Nebraska, this transaction would be subject to the approval of the Commission. As of
3 March 16, 2007, the sale of Aquila's natural gas business to Black Hills Corp had not
4 been submitted to the Nebraska Public Service Commission for approval.

III. SUMMARY OF TESTIMONY

Q. Please summarize your testimony.

A. In the remaining sections, I lay out principles of rate regulation, make recommendations regarding Aquila's proposed cost of service and cost of capital, and recommend a rate of return on common equity for Aquila.

Q. Please summarize your recommendations.

A. My recommendations to the Commission are as follows:

- Allow Aquila the opportunity to earn a 10.0 percent rate of return on common equity.
- Allow Aquila to recover a cost of debt of 7.02 percent
- Disallow the following Aquila adjustments:
 - Adjustment No. 1 – Capital Additions
 - Adjustment No. 6 – Payroll Annualization
 - Adjustment No. 7 – Variable Compensation Plan Change
 - Adjustment No. 9 – Economy of Scale (“EOS”)
 - Adjustment No. 15 – Contributions and Dues Adjustment
 - Adjustment No. 16 – Benefit Adjustment
 - Adjustment No. 18 – Annualized Postage Adjustment
 - Adjustment No. 19 – Annualize/Normalize Insurance Costs
- Modify the following Aquila adjustments:
 - Adjustment No. 4 – Annualized Depreciation Reserves
 - Adjustment No. 10 – Merit Increase/Union Increase
- Allow the following Aquila Adjustments
 - Adjustment No. 8 – Rate Case Expense
 - Adjustment No. 13 – Bad Debt
 - Adjustment No. 14 – Advertising Reclassification
 - Adjustment No. 17 – Property Tax Expense
 - Adjustment No. 20 – Raytown Lease Adjustment
 - Adjustment No. 21 – Graphical User Interface
- Do not adopt Aquila's proposals in the following areas:
 - Weather Normalization Adjustment
 - Revenue Normalization Adjustment
 - Limited Cost Recovery
- Adjust Aquila's Cash Working Capital

Public Advocate witness Mr. Albert D. Bartsch has additional recommendations concerning cost of service study and rate design, adjustments not addressed in this testimony, and other items. Mr. Bartsch also quantifies the effects of my recommendations on Aquila's revenue requirement.

Q. Please outline the remainder of your testimony.

A. The remainder of my testimony consists of the following sections:

- Section IV. Rate regulation principles
- Section V. Aquila's cost of capital
- Section VI. Adjustments to test year data
- Section VII. Cash working capital and lead lag studies
- Section VIII. Aquila's RNA, WNA, and LCR Proposals
- Section IX. Energy Efficiency Programs
- Section X. Confidential Section

IV. RATE REGULATION PRINCIPLES

Q. What rate regulation principles did you use in examining Aquila's filing?

A. I used the principles of the test year, used and useful investment, necessary costs, representative costs and known and measurable changes.

Q. Why is a review of these rate regulation principles important in examining Aquila's Application?

A. This review is an important starting point in examining Aquila's Application because the Company includes an extraordinary number of items that are inconsistent with these principles. The Commission should not approve Aquila initiatives that are undertaken beyond the end of the test year.

Q. Please describe the "historic test year" principle.

A. A test year is a period of time used to estimate sales volumes, expenses, and investments that are representative of the period for which rates are being set. A historic test year should include data from a twelve-month period already completed, which are adjusted for known and measurable changes occurring after the test year to better reflect future volumes, expenses, and investments. The principle behind the historic test year is that the data used are "representative" (see below) of a utility's condition.

The Nebraska Administrative Code Title 291, Chapter 9, Section 001.01k defines a test year as,

"Either a consecutive twelve-month period commencing on the proposed effective date of the rate increase or a base year adjusted for known and measurable changes."

1 In this Docket, Aquila has chosen the latter, a historic test year, rather than the former, a
2 future test year. In doing so, the utility is obligated to show that any adjustments are
3 “known and measurable.”

4 **Q. Please describe the “known and measurable” change principle.**

5 A. The known and measurable change principle states that adjustments may be made to the
6 test year costs for known and measurable cost changes so that the test year represents
7 costs that Aquila can expect to incur during the period for which rates are being set.
8 Changes are “known” if they are certain (have actually taken place) and are “measurable”
9 if the amount of the change is also known.

10 **Q. Please describe the “used and useful” investment principle.**

11 A. The used and useful investment principle states that in order for costs associated with a
12 utility’s investments in plant or other property to be included in customers’ rates, the
13 investment must be used to provide utility services and must be useful in the provision of
14 utility services. Some utility investments are used but not useful and some are useful but
15 not used. For example, a main line may be useful, but if peak loads are not great enough,
16 it may never be fully used, and thus would represent excess investment. Utility
17 investments, to the extent that they are not both used and useful to utility ratepayers,
18 cannot be recovered from ratepayers.

19 **Q. Please describe the “necessary costs” principle.**

20 A. The necessary cost principle states that the operation and maintenance costs of a utility
21 may be recovered from a utility’s customers only if these costs are necessary for the
22 provision of utility service. A cost is necessary if a utility must incur it to provide utility
23 service.

1 **Q. Please describe the “representative costs” principle.**

2 **A.** The representative costs principle states that a utility’s rates must be based upon costs
3 that are representative of the period for which rates are being set. For costs to be
4 included in a test year, the costs should be recurring in nature and reflect the level of cost
5 that is necessary for the provision of utility service. For example, if a utility incurs a one-
6 time expense necessary to the provision of service to its customers and includes the entire
7 amount in the test year, the utility would over-collect from ratepayers in periods
8 following the test year.

9 In some ways, this principle is akin to the “matching concept” in accounting,
10 which holds that “when revenues are reported, the expenses incurred to generate those
11 revenues should be reported in the same accounting period.”⁴

⁴ Definition taken from Haskins, Mark E. et al. *Financial Accounting and Reporting*, Irwin: Burr Ridge, Illinois, 1993, p. 766.

1

2 **SECTION V. COST OF CAPITAL**

3

4 **Return on Equity**

5 **Q. What rate of return on common equity do you recommend for Aquila Inc.'s**
6 **Nebraska retail natural gas distribution business?**

7 A. I recommend that Aquila be allowed the opportunity to earn a 10.0 percent rate of return
8 on common equity.

9 **Q. Why should the Commission allow Aquila the opportunity to earn a 10.0 percent**
10 **rate of return on common equity?**

11 A. The Commission should allow Aquila the opportunity to earn a 10.0 percent rate of return
12 on common equity because 10.0 percent represents the central tendency of my
13 Discounted Cash Flow (DCF) and Capital Asset Pricing Model (CAPM) analyses of a
14 group of natural gas distribution companies comparable to Aquila's Nebraska retail
15 natural gas operations.

16 **Q. What is the basis of the rate of return criteria presented in your testimony?**

17 A. The basis of the rate of return criteria presented in my testimony was set forth in the U.S.
18 Supreme Court's Bluefield (1923) and Hope (1944) cases. The Bluefield case states that
19 return to a public utility should be, "equal to that generally being made at the same time
20 and in the same general part of the country on investments in other business undertakings
21 which are attended by corresponding risks and uncertainties." Bluefield Waterworks &
22 Improvement Co. v. Public Service Board of West Virginia, 262 U.S. 679, 692 (1923).
23 The Hope case states that, "the return to the equity owner should be commensurate with

1 returns on investments in other enterprises having corresponding risks.” Federal Power
2 Commission v. Hope Natural Gas Co., 320 U.S. 591, 603 (1944). The Bluefield and
3 Hope cases, therefore, require that we look to companies with comparable risks to
4 determine an appropriate rate of return on common equity for Aquila.

5 Group of Comparable Companies

6 **Q. What group of comparable companies did you analyze to estimate a cost of equity**
7 **capital for Aquila Inc.’s Nebraska natural gas operation?**

8 A. The group of comparable companies that I analyzed to estimate a cost of equity capital
9 for Aquila were taken from the group of 15 companies identified by the *Value Line*
10 *Investment Survey* as the Natural Gas Distribution segment. *Value Line* defines the
11 Natural Gas Distribution segment as follows: “The distribution operations of gas utilities
12 are regulated by state agencies, which set the allowed rates of return these companies are
13 permitted to earn.” (p. 459 of the December 15, 2006 edition of *Value Line*). In the latest
14 edition (March 16, 2007), *Value Line* writes,

15 Most of the gas distribution companies derive over 85% of their earnings
16 from local natural gas distribution. Like their larger cousins, the electric
17 power distribution companies, gas distribution companies are allowed by
18 their state-based public service commissions to earn a limited return on
19 equity, generally in the 10% - 12 % range.⁵
20

21 A list of these 15 companies is included as Exhibit_(WLG-D), Schedule 5, page 1.

22 **Q. Is Aquila Inc. included in this group?**

23 A. No, *Value Line* classifies Aquila, Inc. as part of the Electric Utility (Central) Industry
24 group.
25

⁵ *Value Line Investment Survey*, Part 3: Ratings & Reports, March 16, 2007, p. 460.

1 **Q. Is Black Hills Corporation included in the Natural Gas Distribution group?**

2 A. No. Black Hills Corporation is included as part of the Electric Utility (West) Industry
3 group in *Value Line*.

4 **Q. Why is the natural gas distribution segment the appropriate comparable group?**

5 A. The natural gas distribution segment is the appropriate comparable group because it
6 includes the closest “pure play” companies to the Nebraska retail natural gas distribution
7 business of Aquila. To calculate an appropriate cost of capital for the Nebraska retail
8 operations of Aquila, we need to select a group of companies whose businesses are
9 closely matched in scope, and would share similar risks, to the company at issue.

10 **Q. In performing your analyses, did you exclude any companies from this group of**
11 **comparable companies?**

12 A. Yes. In performing my analyses, I excluded three of the fifteen companies.

13 One company was excluded because of its dividend policy: SEMCO Energy is not
14 currently paying a dividend, and has not paid one since 2004.

15 Two other companies, Cascade Natural Gas and Keyspan, were excluded because
16 of their involvement in mergers. SEMCO is also involved in a merger,⁶ but it was
17 previously excluded.

18 **Q. Have you included merging companies in your comparable groups in the past?**

19 A. Yes, in other analyses that I have performed, I have included companies involved in
20 merger proceedings. As the energy industry continues to consolidate, I am concerned
21 that excluding such companies may leave a sample size too small to produce meaningful

⁶ SEMCO has agreed to be purchased by Cap Rock Holdings Corp., as reported in *Value Line*, March 16, 2007, p. 470.

1 analytical results. Other analysts tend to exclude such companies under the belief that
2 their stock prices no longer reflect their value as a stand-alone entity.

3 In the specific case of these two firms, I believe that circumstances warrant their
4 exclusion from the comparable group. Cascade Natural Gas is in the process of being
5 purchased by Montana Dakota Utilities (MDU) in an all cash deal for \$26.50 per share.⁷
6 Since the merger was announced last summer, the stock has been trading in a narrow
7 range around the sale price. Likewise, Keyspan is in the process of being purchased by
8 Britain's National Grid, in an all cash deal for \$42 a share.⁸ Since that deal was
9 announced last year, the stock has traded in a fairly narrow range below the sale price.
10 Therefore, I conclude that in these two instances, involving all cash sales, the
11 assumptions regarding the stock price are correct.

12 DCF Analysis for Comparable Companies

13 **Q. How should the Commission determine the cost of common equity for natural gas**
14 **distribution utilities in Nebraska?**

15 A. As discussed below, the Commission should rely on DCF and CAPM analyses to
16 determine the cost of common equity for natural gas distribution utilities.

17 **Q. What is a DCF analysis?**

18 A. A Discounted Cash Flow (DCF) analysis is a method for estimating a company's cost of
19 common equity. The DCF model states that the cost of common equity, for dividend
20 paying stocks, is equal to the stock's expected dividend yield plus expected growth in
21 dividends. Because most utility stocks are dividend-paying stocks, the DCF analysis is
22 especially useful for estimating a utility's cost of common equity. The DCF analysis is a

⁷ See *Value Line Investment Survey*, March 16, 2007, p. 463.

⁸ See *Value Line Investment Survey*, December 15, 2006, p. 463.

1 sound model commonly used by regulatory commissions for determining the cost of
2 common equity.

3 **Q. Why should a DCF analysis be used to estimate a cost of common equity in this**
4 **case?**

5 A. A DCF analysis should be used to estimate the cost of common equity in this case
6 because employing a DCF model using current stock price, dividend, and dividend
7 growth rate information produces a cost of common equity estimate that satisfies the rate
8 of return criteria for regulated businesses as set forth in the U.S. Supreme Court's Hope
9 and Bluefield cases discussed earlier in my testimony in this case.

10 **Q. What form of the DCF model did you use to determine Aquila's cost of common**
11 **equity?**

12 A. I used a form of the DCF model commonly known as the annual compounding model,
13 which "recognizes that dividends are paid in a discrete manner rather than a continuous
14 manner and the expected dividend rate is utilized."⁹

15 **Q. Please explain the form of the DCF model that you used?**

16 A. I employed the following form of the DCF model:

17
$$k = \text{DIV}_1 / P_0 + g \quad \text{where,}$$

18 k = the rate of return expected on securities of similar risk,

19 DIV_1 = the dividend expected during the next twelve months,

20 P_0 = the current stock price, and

21 g = the expected dividend growth rate.

22 The quantity DIV_1 / P_0 is also known as the expected dividend yield.

1 **Q. How did you estimate the dividend expected during the next twelve months,**
2 **“DIV₁”?**

3 A. I estimated the dividend expected during the next twelve months, DIV₁, by relying on the
4 *Value Line* estimate for dividends to be declared for calendar year 2007 for the 12
5 companies in my sample.

6 **Q. Why is this method of estimating DIV₁ appropriate?**

7 A. The method I used to estimate DIV₁ is appropriate because the form of the DCF model I
8 used requires that I estimate dividends for the next year. This method reflects current
9 information, and recognizes that companies will, on average, increase dividends from
10 current levels.

11 Stock Price Based on Most Recent Three Months' Ending Prices

12 **Q. How did you estimate the current stock price, P₀?**

13 A. I estimated the current stock price, P₀, by taking an average of the monthly high and low
14 stock prices over the three-month period December 2006, January 2007, and February
15 2007, as reported in the January 2007 and February 2007 issues of the *Standard and*
16 *Poor's Security Owner's Stock Guide* (first two months) and the Reuters reporting service
17 (for the third month).

⁹ Parcell, David C., *The Cost of Capital—A Practitioner's Guide*. 1997 Edition. Society of Utility and Regulatory Financial Analysts, page 8-7.

Estimate of Current Dividend Yield

Q. What is your estimate of current dividend yields for Natural Gas Distribution companies in your sample?

A. I estimate that the average dividend yield for the 12 Natural Gas Distribution companies in my sample is 3.4 percent.¹⁰

Expected Dividend Growth Rate Estimated Using Four Methods

Q. How did you estimate the expected dividend growth rate “g”?

A. To estimate the expected dividend growth rate, “g”, I used the following four approaches:

- Using *Value Line*’s forecasted dividends to estimate dividend growth.
- Using *Value Line*’s forecasted earnings to estimate dividend growth.
- Performing fundamental analysis of sustainable dividend growth using estimated 2007 returns and retention ratios from *Value Line* (2007 ratios).
- Performing analysis of sustainable dividend growth using *Value Line* projections for future returns and retention ratios (projected ratios).

Q. What are the *Value Line* dividend growth estimates used in your analysis?

A. *Value Line* estimates in its reports the annual per share dividends to be paid by each company up to five years in the future. The estimated annual per share dividends used in my analysis are from the March 16, 2007, issue of the *Value Line Investment Survey*. To calculate the estimated dividend growth rates I use in my analysis, I took the simple average of the compound annual growth rates of annual per share dividends estimated by *Value Line* between the periods 2004-2006 and 2010-2012. The average dividend

¹⁰ See Exhibit_(WLG-D), Schedule 5, Page 2, for this calculation.

growth rate estimate for my sample of 12 companies was 3.2 percent. This calculation is shown in Exhibit_(WLG-D), Schedule 5, page 3, column 2.

Q. Why do you use estimates of future dividend growth in your analysis?

A. I use estimates of future dividend growth in my analysis because the DCF model is a forward looking one. That is, the DCF model is designed to discount *future* cash flows. *Value Line*'s estimates of future dividend growth are widely available to investors and reflect current available market dividend growth information for the period covered.

Q. What are the *Value Line* earnings growth estimates used in your analysis?

A. *Value Line* estimates in its reports the annual per share earnings of each company up to five years in the future. The estimated annual per share earnings used in my analysis are from the March 16, 2007, issue of the *Value Line Investment Survey*. To calculate the estimated earnings growth rates I use in my analysis, I took the simple average of the compound annual growth rates of annual per share earnings estimated by *Value Line* between the periods 2004-2006 and 2010-2012. The average earnings growth rate estimate for my sample of 12 companies was 4.8 percent. This calculation is shown in Exhibit_(WLG-D), Schedule 5, page 3, column 1.

Q. Please explain the fundamental analysis of sustainable dividend growth used in your analysis.

A. The fundamental analysis of sustainable dividend growth used in my analysis is calculated by multiplying a company's earnings retention percentage (also known as the "plowback ratio") by its return on book equity. For example, the dividend growth rate that could be sustained if a company retained twenty percent of its earnings and earned ten percent on its book equity would be two percent ($20\% \times 10\% = 2\%$).

1 **Q. Why is fundamental analysis of sustainable dividend growth appropriate for**
2 **estimating the dividend growth rate in a DCF analysis?**

3 A. A fundamental analysis of sustainable dividend growth is appropriate for estimating the
4 dividend growth rate in a DCF model because the result of such an analysis is a dividend
5 growth rate that investors could expect a company to maintain in the future.

6 **Q. What are the sustainable dividend growth rate estimates produced by the 2007 and**
7 **projected earnings and retention ratios?**

8 A. The 2007 ratios and projected future (2010-2012) earnings and retention ratios produced
9 sustainable dividend growth rate estimates of 5.4 percent and 5.3 percent, respectively,
10 for the full sample of 12 companies. These calculations are shown in Exhibit_(WLG-D),
11 Schedule 5, page 4.

12 **Q. What range for the cost of common equity is produced by these four methods of**
13 **estimating dividend growth rates for the full sample of comparable companies?**

14 A. The cost of common equity produced by these four methods of estimating dividend
15 growth rates ranges from 6.6 percent to 8.8 percent for the full sample of comparable
16 companies. The cost of common equity produced using forecasted dividends was 6.6
17 percent and using forecasted earnings was 8.2 percent. The 2007 and projected earnings
18 and retention ratios produced cost of common equity estimates of 8.8 percent and 8.7
19 percent, respectively.

Projection Method	Dividend Yield	Plus	Projected Growth	Equals	Return On Equity
Dividend Growth	3.4%		3.2%		6.6%
Earnings Growth	3.4%		4.8%		8.2%
Sustainable Growth (2007)	3.4%		5.4%		8.8%
Sustainable Growth (Future)	3.4%		5.3%		8.7%

1 **Q. Do you have any concerns with the cost of common equity estimates, shown in the**
2 **first column of the above table, produced using forecasted dividend growth rates in**
3 **this case?**

4 A. Yes, I do have concerns with the results using forecasted dividend growth rates, which
5 are shown in the first row of the above table. In the DCF model, the term “g” is supposed
6 to represent a company’s long-term dividend growth rate. Given the significant change
7 now taking place in the energy utility industry, I believe that the *Value Line* five-year
8 forecasts may anticipate reluctance by the management of energy utilities to raise
9 dividends during uncertain times. Consequently, the results produced using *Value Line*
10 five-year forecasted dividends may underestimate a utility’s true cost of capital.

11 Capital Asset Pricing Model (CAPM) Analysis

12 **Q. Did you conduct any other return on equity analysis?**

13 A. Yes. For the 12 companies in the natural gas distribution group, the cost of common
14 equity was estimated using a second analytical tool, the capital asset pricing model or
15 CAPM. CAPM is based on the premise that investors try to maximize the return on their
16 portfolios while minimizing the risk associated with that return.

17
18 The CAPM formula is as follows:

19
$$k = R_f + \beta(R_m - R_f)$$

20 Where, k is the cost of common equity, R_f is the risk free rate, R_m is the return on the
21 “market” portfolio, and β (“Beta”) is the measure of the sensitivity of an asset’s return to
22 market changes.

1 The risk-free rate was estimated using the current yield on 30-year U.S. Treasury
2 bonds.¹¹ Betas for each company in the sample were taken from the *Value Line*
3 *Investment Survey*. The equity risk premium ($R_m - R_f$) was estimated by subtracting the
4 arithmetic mean of total returns on long-term government bonds over the period 1926 to
5 2006 from the arithmetic mean of total returns on large company stocks over the same
6 period.¹²

7 As shown on Schedule 5, Page 5, the CAPM analysis produced an average cost of
8 equity capital of 10.4 percent for the 12 companies in the sample.

9 Recommendation

10 **Q. Given your concerns about the DCF results obtained using *Value Line* forecasted**
11 **dividends, what cost of common equity do you recommend for Aquila's natural gas**
12 **operations ?**

13 A. As stated before, I recommend a 10.0 percent cost of common equity for Aquila's retail
14 natural gas distribution business. My concerns about the DCF results obtained using
15 *Value Line* dividend growth rates to estimate dividend growth rates have caused me to
16 rely more on the DCF results obtained using sustainable growth rates and the CAPM
17 results. Combining the DCF cost of common equity estimate of 8.8 percent (relying on
18 earnings growth) and with the CAPM result of 10.4 percent produces a central tendency
19 of approximately 9.6 percent, which I have rounded to 10.0 percent, consistent with the
20 lower range of industry actuals as reported by *Value Line*.

¹¹As reported in the *Value Line Section and Opinion* for March 9, 2007, p. 4819.

¹² Morningstar's "Risk Premia Over Time Report: 2007", Table 1: Summary Statistics of Annual Total Returns, page 4.

1 Testimony of Aquila Witness Murry

2 **Q. Have you reviewed the pre-filed direct testimony of Aquila witness Dr. Donald A.**
3 **Murry?**

4 A. Yes. I have reviewed the pre-filed direct testimony of Aquila witness Dr. Donald A.
5 Murry.

6 **Q. Do you agree with his conclusions regarding cost of equity capital?**

7 A. No. Dr. Murry recommends a cost of equity capital of 12 percent.

8 Murry DCF Analysis

9 **Q. Which companies does Company witness Murry include in his comparable group?**

10 A. Dr. Murry included only eight companies in his comparable group. All eight were
11 companies that were also included in my comparable group.

12 However, he eliminated four additional companies that are included in my group.
13 UGI Corp was eliminated from his group on the basis that it is not primarily a gas
14 distributor. UGI derives more than half of its revenue from the sale of propane. We
15 presume that Dr. Murry eliminated this company because less than half of its revenue
16 arises from *natural* gas distribution. He also deleted AGL and Atmos from his sample
17 because of their size. He also omits Southern Union.

18 **Q. Do you agree with Dr. Murry's DCF analysis?**

19 A. Other than this disagreement over inclusion of companies in the comparable group, I do
20 not have significant issues with how Dr. Murry conducted his DCF analysis. I prefer my
21 DCF analysis, for the reasons stated above.

1 Murry CAPM Analysis

2 **Q. Do you agree with Dr. Murry's application of the CAPM model?**

3 A. No, I do not agree with Dr. Murry's application on the CAPM model. My disagreements
4 center on three areas:

- 5 • Selection of risk-free rate.
- 6 • Selection of the equity risk premium
- 7 • Application of a size adjustment

8 **Q. What rate does Dr. Murry select for use as a risk free rate?**

9 A. Although Dr. Murry does not specify which rate he selects for use as the risk free rate, I
10 presume he has been consistent in his application of the Ibbotson risk premium he
11 selected and used the 20-year U.S. Treasury bond yield as his risk free rate. The
12 Commission should note that yields on this maturity have fallen from the 5.08 percent
13 used in Murry's work to 4.76 percent today.¹³

14 I believe it is inappropriate to use the 20-year maturity as the risk free rate for three
15 reasons:

- 16 • It is shorter than the 30-year bond. The 30-year bond is the longest term
17 available, best matching the extremely long-term nature of the investments made
18 in natural gas utilities.
- 19 • Not issued. Strictly speaking, the U.S. Treasury does not issue 20-year bonds. It
20 only issues new 10-year and 30-year bonds. Therefore, its yield cannot be
21 directly observed as new bonds are issued, but must be inferred from yields in the
22 secondary market of longer maturities.

- Yields lie outside yield curve. As can be seen in the Federal Reserve data, yields for the 20-year maturity are 23 basis points above the 10-year bond and 10 basis points above the 30-year bond.¹⁴ No other intermediate issue is higher or lower than both of the two surrounding maturities, making this maturity an anomaly along the otherwise smooth (although inverted) yield curve.

Q. What equity risk premium does Dr. Murry use?

A. Dr. Murry uses an equity risk premium of 7.1 percent, apparently based on Ibbotson's risk premium of large company stock total returns less long-term government bond total returns. Rather than relying upon the method used by Ibbotson to calculate his figure, I prefer to calculate the premium more directly by relying on intermediate data, exactly as stated in the classic formula. The resulting difference is substantial, 6.5 percent versus 7.1 percent.

Q. Do you agree with Dr. Murry's size adjustment?

A. No. I do not agree with Dr. Murry's size adjustment. Aquila's natural gas operations in Nebraska are relatively small, compared to other similar companies. However, that comparison is unfair, in that Aquila's natural gas operations are part of a much larger organization serving natural gas customers in other states. This organization is part of a still larger one, with electric utility operations in additional states. In all other aspects of ratemaking, especially the allocation of corporate overhead costs, we accept the reality of Aquila's actual structure. In this instance, Dr. Murry seeks to make an exception.

More specifically, I am troubled by the fact that Dr. Murry selects his comparable group based on size (limited to companies with a market capitalization of less than \$2

¹³ See Federal Reserve Statistical Release H.15 "Selected Interest Rates", March 12, 2007, data for Week Ending March 9. Included as Exhibit_(WLG-D), Schedule 6, page 1.

1 billion)¹⁵ and then applies a size adjustment to his CAPM analysis.¹⁶ I see at least three
2 problems with this approach.

- 3 • Arbitrary cutoff. Dr. Murry applies the Ibbotson Associates size adjustment, but
4 uses different size criteria. Ibbotson's "mid-cap" market capitalization ranges
5 from \$1.7 billion to \$7.2 billion and his low cap ranges from \$0.6 billion to \$1.7
6 billion. Dr. Murry's tries to compensate by using both the mid cap and low cap
7 premia, but the whole exercise gives the appearance of apples to oranges analysis.

8 More significantly, we would have to eliminate one additional company
9 from the Dr. Murry's group if we relied upon more recent Value Line data. In the
10 most recent issue Value Line reports that NICOR enjoys market capitalizations
11 above \$2 billion.

- 12 • Assumption does not hold for industry. The assumption behind the size
13 adjustment is that the stock returns of smaller companies are inherently more
14 risky than those of larger companies. However, this assumption does not appear
15 to hold for the natural gas distribution industry.

16 As shown in Exhibit_(WLG-D), Schedule 7, page 1, smaller firms in the
17 industry do not appear to be more risky than larger firms, as measured by beta.
18 Table 1 shows the full sample of fifteen firms from *Value Line*'s Natural Gas
19 Distribution group, grouped by Dr. Murry's \$2 billion market capitalization

¹⁴ Ibid.

¹⁵ Murry, p. 11, lines 11-12.

¹⁶ Murry, p. 34, line 12 through p. 35 line 7.

dividing line.¹⁷ The larger firms have a riskier beta, 0.98 compared to the smaller firms' 0.81.

Moving the dividing line up to \$2.1 billion in market capitalization shifts NICOR and back to the smaller group, more in line with Dr. Murry's comparable group. Now the larger firm group still has a greater average beta, 0.91 vs. the smaller firms' 0.86. It is difficult to see how this industry group fits the usual size pattern, as far as risk is concerned.

- Premia have fallen. Since Dr. Murry performed his analysis in late 2006, new data have been produced by Ibbotson Associates¹⁸ on size and risk premiums. According to their 2007 report, the "low-cap" size premium has fallen from 1.81 percent to 1.76 percent. The "mid-cap" premium has fallen from 1.02 percent to 0.97 percent.¹⁹

Q. Adjusting for current data, how does Dr. Murry's CAPM analysis appear today?

A. If we adjust for current data, Dr. Murry's CAPM analysis²⁰ appears quite different. We now have new data on market capitalization,²¹ interest rates,²² betas,²³ and size premia.²⁴ Adjusting for these new data, which eliminates from the sample, Dr. Murry's calculation of 12.68 percent now drops to 12.09 percent, a drop of nearly 0.6 percent. These results are shown in Exhibit_(WLG-D), Schedule 7, page 2.

¹⁷ Tables 1 and 2 use data from *Value Line's* March 16, 2007, issue for both market capitalization and beta information.

¹⁸ Now owned by Morningstar.

¹⁹ See Morningstar's "Risk Premia Over Time Report: 2007, Table C-1: Key Variables in Estimating the Cost of Capital, page 5.

²⁰ Dr. Murry's CAPM analysis appears in his Schedule DAM-23.

²¹ From *Value Line's* March 16, 2007 issue.

²² From Federal Reserve statistical release H.15, March 12, 2007, p. 1, included with my Exhibit_(WLG-D), Schedule 6.

²³ From *Value Line's* March 16, 2007, issue.

1 Capital Structure

2 **Q. Have you reviewed Dr. Murry's testimony on capital structure?**

3 A. Yes. I have reviewed Dr. Murry's testimony on capital structure.²⁵ In his testimony, Dr.
4 Murry proposes a capital structure divided between equity and long-term debt capital,
5 consisting of 50.73 percent equity and 49.27 percent long-term debt. This calculation is
6 shown in his Schedule DAM-5

7 **Q. Is such a capital structure appropriate for Aquila's natural gas operations?**

8 A. Yes. A 51/49 capital structure is well-within the range found for natural gas distribution
9 utilities and is consistent with a well-capitalized, high quality utility company. My
10 Schedule 8 shows the range of capital structures for the sixteen companies included in
11 *Value Line's* natural gas distribution group. The median common equity ration for the
12 group is, in fact, 50 percent, within one percent of the level proposed by Dr. Murry. The
13 range for the sixteen companies runs from 32.0. percent to 67.0 percent.

14 Cost of Long-Term Debt

15 **Q Have you reviewed Dr. Murray's testimony regarding Aquila's cost of long-term**
16 **debt and his recommendation?**

17 A. Yes, I have reviewed Dr. Murry's testimony on Aquila's cost of long-term debt. His
18 Schedule DAM-8 proposes a cost of debt for Aquila of 7.13 percent.

19 **Q. Is Dr. Murry's cost of debt appropriate for Aquila's natural gas operations?**

20 A. No. Dr. Murry's proposed cost of long-term debt is not consistent with the proposed
21 capital structure and is not appropriate for Aquila's natural gas operations. Dr. Murry's

²⁴ See Morningstar's "Risk Premia Over Time Report: 2007, Table C-1: Key Variables in Estimating the Cost of Capital, page 5.

²⁵ See Murry, pages 12 through 14.

Schedule DAM-8 takes Aquila's embedded cost of long-term debt and makes two adjustments.

Q. What adjustments did Dr. Murry make to Aquila's cost of long-term debt?

A. As Dr. Murry explains in his response to Public Advocate Data Request PA-31c,²⁶ he adjusted two interest rates, as follow:

For the 11.875% series, a comparison of current new issue bond pricing was obtained along with a [sic] estimate of a new issue price for Aquila from Lehman Brothers assuming a BBB- rating. See attached schedule. The 6.05% includes any issuance costs related to this series. The 7.95% note series represents the effective interest cost on this series at its original issue in 2001 before the credit downgrades.

The second adjustment, to the 7.95% Series, seems reasonable. By making this adjustment, the ratepayer is back to where the company would have been, had it maintained an investment grade credit rating, as is the industry norm. It is the second adjustment, to the Sr. 11.875% Note Series, that I find troublesome.

Q. What adjustment should Dr. Murry have made to the Series?

A. Dr. Murry should have adjusted the interest rate on the Sr. 11.875% Note Series to reflect the risk of a comparable natural gas distribution utility. In his testimony, Dr. Murry points out that none of his eight comparable companies has an S&P credit rating below BBB "and six of the eight are "A" rated or above. Yet he chooses a BBB- rating when adjusting his cost of debt.

As shown in my Schedule 8, none of the seven natural gas distribution utilities with a common equity ratio above the 50 percent median has an S&P credit rating below BBB+. If Aquila wishes to use a higher common equity ratio, one above 50 percent with

²⁶ Included with this testimony as Exhibit_(WLG-D), Schedule 9.

1 its greater weight on the use of more expensive equity capital, it will need to adjust its
2 cost of long-term debt to reflect the higher credit quality of companies in that class.

3 **Q. What is the difference in cost between a BBB- utility and a BBB+ utility's debt?**

4 A. A higher-rated utility enjoys a lower cost of debt, reflecting its superior credit quality.

5 According to Reuters, as reported in www.bondsonline.com, the basis difference between
6 "BBB-" and "BBB+" rated utilities was 20 basis points for 30-year issues as of March 5,
7 2007.

8 **Q. What adjustment do you propose to make to Aquila's cost of debt?**

9 A. Based on the recently reported 20 basis point differential for long-term debt between
10 "BBB-" and "BBB+" rated utilities, I propose to reduce Dr. Murry's 6.05 percent interest
11 for the Sr. 11.875% Note Series issues rate to 5.85 percent. Making this substitution to
12 the interest rate for this Series reduces the overall cost of long-term debt to 7.02 percent.
13 This recalculation can be shown in my Schedule 10A, which reproduces Aquila's
14 Schedule DAM-8.

1

2 **V. ADJUSTMENTS TO TEST YEAR DATA**

3

4 **Q. What test-year does Aquila use in its Application?**

5 A. According to the Pre-Filed Testimony of Aquila witness Richard G. Petersen,²⁷ Aquila
6 proposes to use a test year (base year) that begins on July 1, 2005 and ends on June 30,
7 2006.

8 **Q. What changes does Aquila propose to make to its test year data?**

9 A. In Aquila's petition, Exhibit VI, Schedule B, lists 22 adjustments that the company seeks
10 to make to its base year data. In his Pre-Filed Direct Testimony, Aquila witness Petersen
11 outlines the 22 adjustments proposed by the utility to their test year expenses and rate
12 base.²⁸ A number of these adjustments were needed to make the base year representative
13 of what the utility's costs will be during the period in which the new rates will be in
14 effect.

15 As Reeser explains,

16 "Adjustments to the recorded figures involve such things as known
17 or proposed changes in operating procedures, the elimination of non-
18 recurring expenses, the normalization of experienced weather, future wage
19 settlements, load growth or conservation, changes in inventory costs,
20 depreciation adjustments, and changes in tax rates"²⁹

21 Phillips adds,

22
23 "For many years, Commissions have adjusted test-year data for
24 "known changes"; that is, a change that actually took place during or after

²⁷ Direct Testimony of Richard G. Petersen, p. 4.

²⁸ See Petersen testimony, pages 6 through 18.

²⁹ Reeser, Marvin P. *Introduction to Public Utility Accounting*, American Gas Association: Second Edition, 1984, page 33.

1 the test year (such as a new wage agreement that occurred toward the end
2 of the year).”³⁰
3

4 **Q. Does the Public Advocate support these Adjustments?**

5 A. The Public Advocate supports some of Aquila’s proposed adjustments to the test year,
6 opposes others, and seeks to modify the rest. Public Advocate witness Mr. Albert D.
7 Bartsch discusses Adjustment Nos. 2, 3, 5, 11, 12, and 22. I discuss the remainder below.
8 My discussion of Adjustment Nos. 4 and 15 is included in a confidential section.

9 **Q. Please explain Adjustment 1 – Capital Projects.**

10 A. Aquila seeks to include \$12,776,870 in rate base for projects that they anticipated
11 would be completed during the second half of 2006 and the first half of 2007

12 What is not clear from Aquila’s filing is whether the additions have been
13 made, whether they are used and useful, and whether their costs are known and
14 measurable. Without this information, we cannot provide assurance to the
15 Commission that this Adjustment meets the criteria mentioned in Phillips of
16 “actually occurred” and “known changes.” For this reason we recommend that
17 this Adjustment be disallowed.

18 Furthermore, according to the testimony of Aquila witness Petersen,³¹ Aquila
19 witness Vern Siemek was to support this Adjustment in his testimony. After carefully
20 reviewing Mr. Siemek’s testimony, I can report that no such support was included.

21 This lack of witness support creates a number of additional problems for this
22 adjustment. First, no clear explanation is present in the record of just what items are
23 included in this adjustment nor is any explanation given that would allow the

³⁰ Phillips, Charles F. Jr. *The Regulation of Public Utilities: Theory and Practice*, Third Edition, Public Utilities Reports, Inc.: Arlington, VA, 1993, p. 196.

³¹ See Petersen, page 5, lines 10-11 and page 6, lines 8-9.

Commission to conclude that these additions are “used and useful,” “prudently incurred,” “known and measurable” or any of the other standard tests for inclusion in rates. Without a witness to depose, to direct data requests to, or to cross-examine under oath, inclusion of this Adjustment in the rate base, and, thus, in rates, raises obvious due process problems.

Not even having a witness “adopt” this “orphan” adjustment in a rebuttal round would permit the Public Advocate, Commission staff and consultants, and the Commission itself enough time for a complete examination of what represents a significant item.

Q. Please explain Adjustment No. 4. Annualized Depreciation Reserves

A. As briefly mentioned in Mr. Petersen’s testimony,³² Aquila undertook to update its depreciation rates, based on a study performed by Foster and Associated delivered in June 2006. This study was provided to the Public Advocate in response to Public Advocate Data Request PA-66.

While we have not independently verified the results of the Foster study, assuming that its conclusions are correct, Aquila has not depreciated its assets as quickly as it should have, resulting in the need for a large adjustment to reserves. Of the total adjustment of \$3,031,242,³³ we calculate that \$856,058 is related to this readjustment of reserve balances.

The figures for Adjustment 4 do not match the figures found in the Foster study. However, it appears to us that Aquila has not followed the Foster recommendation to amortize the adjustment over several years and instead has put the entire amount of the

³² See Petersen, page 9, line 14 through page 9-21.

³³ This total includes both an adjustment to depreciation expense and to reserves.

1 adjustment to reserves into the utility's annual depreciation expense. If true, this
2 approach is incorrect: the adjustment to reserves should be a one-time item, not a
3 recurring one. By doing so, Aquila stands to overcollect on its depreciation expense by
4 millions if the new rates remain in effect for any length of time.

5 This adjustment to reserves represents depreciation expense that should have been
6 charged to ratepayers for many years. Those ratepayers were undercharged, but to go
7 forward and collect this cost from current and future ratepayers would mismatch costs
8 and benefits and would be a classic example of unrepresentative costs. The Commission
9 should disallow the Aquila proposed Adjustment amount on that basis. Instead, the
10 Commission should permit an Adjustment 4 amount equal to \$2,175,184, as shown in
11 Exhibit_(WLG-D), Schedule 10B.

12 (See Section 10, Confidential Section, for additional information on this
13 adjustment.)

14 **Q. Please explain Adjustment 6 – Payroll Annualization**

15 A. This adjustment is described in the testimony of Aquila witness Petersen.³⁴ Aquila seeks
16 to annualize the company's payroll expense as of August 15, 2006, adding an additional
17 \$2,045,629 to the utility's test-year payroll costs. As Petersen explains, it also includes
18 the cost associated with vacant positions "that are in the process of being filled."

19 It has been our experience that such an adjustment is made based on the final
20 payroll period of the test year. If Aquila wished to include more up-to-date payroll
21 information in its costs, it could have—as we mentioned before—created a prospective
22 test year or simply ended the test year July 31 or August 31. Taking out-of-period

³⁴ See Petersen, page 7, line 3 through page 9.

1 payroll costs as the basis for an annualization adjustment violates the principle of the test
2 year and for that reason this Adjustment should be disapproved by the Commission.

3 The inclusion of vacancies in calculating the adjustment is even more troubling
4 than the timing issue. At any point in time, a large organization is bound to have a
5 significant number of vacant positions. To base an expense on all authorized positions,
6 filled or otherwise, simply is not representative of a utility's actual costs, at any point in
7 time.

8 In Public Advocate Data Request PA-136, we asked for an update on the open
9 positions included in this adjustment. Aquila's response, included as Schedule 12,
10 indicates that 13 of 19 positions have been filled since August 15, 2006, but that six
11 positions will not be filled, as they are listed either as "inactive" or "hold." This
12 characterization directly contradicts Mr. Petersen's claim that these positions "are in the
13 process of being filled." Allowing an adjustment based on positions that are "inactive" or
14 "hold" would result in an over-recovery of costs by the utility.

15 Furthermore, the utility has not reduced the size of this adjustment based on
16 additional positions that have become vacant or been eliminated in the interim since the
17 end of the test year. Aquila's response to Public Advocate Data Request PA-136 shows
18 evidence of the elimination of a least five additional positions, over and above those
19 contemplated by Aquila at the time they filed this case.³⁵

20 In conclusion, if we could overcome the problem associated with using an out-of-
21 period payroll as the basis for this Adjustment, we cannot support the use of unfilled or
22 no longer authorized positions to calculate payroll costs.

³⁵ Aquila's response is included as Exhibit_(WLG-D), Schedule 13.

1 **Q. Please explain Adjustment 7 – Variable Compensation Adjustment**

2 A. This adjustment is described in the testimony of Aquila witness Petersen.³⁶ This
3 adjustment of \$351,618 relates to the utility’s variable compensation or incentive plan for
4 non-union employees. Adjustment 7 only relates to the recent revisions in the plan, as
5 the costs of future payments associated with the previous plan were included in
6 Adjustment 6.

7 The problem with this adjustment is that these payments will not be made until
8 March 2007, as they are based on calendar 2006 activity. At the end of the test-year, and
9 at the time this case was filed, these payments were only “expected”³⁷ to be made. The
10 actual amount may turn out to be significantly higher or lower than the utility’s estimates.
11 As such, this adjustment cannot be classified as known or measurable. Referring back to
12 the quote from Phillips, it had not actually occurred and was not “known” at the time
13 Aquila filed its case. Furthermore, it is not clear whether this estimate includes amounts
14 associated with positions that are not filled or are otherwise no longer eligible for the
15 March 2007 payout.

16 Compounding the problem, Adjustment 7 handles only that portion related to the
17 2006 revisions to the plan. No historic data would exist to guide the estimator on how
18 much this portion of the plan would turn out to be. Without either actual data or
19 historical data to work with, the Commission should disallow this speculative item.

³⁶ See Petersen, page 7, line 3 through page 9.

³⁷ See Petersen, page 9, line 15.

1 **Q. Please explain Adjustment 9 – Economy of Scale (EOS)**

2 A. This adjustment is described in the testimony of Aquila witness Petersen,³⁸ and would
3 result in a reduction of operating expenses totaling \$442,862. This adjustment reflects
4 the reduction in corporate overhead resulting from the sale of a number of Aquila's
5 electric and natural gas utilities in other states. Mr. Peterson claims 27 positions were to
6 be eliminated and implies that making this adjustment would result in a more
7 representative test year.

8 However, in response to Public Advocate Data Request PA-77,³⁹ the company
9 indicates it actually reduced 56 positions, 29 more than anticipated.

10 Even though this adjustment serves to reduce Aquila's overall cost of service, we
11 recommend that the Commission disallow it. In hindsight it has become clear that this
12 adjustment simply was not known and measurable at the end of the test year or at the
13 time the utility filed its case.

14 **Q. Please explain Adjustme nt No. 10. Merit Incentive/Union Incentive**

15 A. As described in Mr. Petersen's testimony,⁴⁰ this proposed adjustment of \$754,825 reflects
16 expected merit increases for non-union employees and a scheduled union pay increase.

17 As for the union pay increase, the Commission should allow the full \$265,246
18 representing the union part of this Adjustment. This dollar amount equals 35.14 percent
19 of the total proposal adjustment. Pay increases arising from union contracts are the
20 textbook example of a known and measurable change that should be included in rates.

³⁸ See Petersen, page 10, line 7 through page 15, line 8.

³⁹ Aquila's response to Public Advocate Data Request PA-77 is included with this testimony as Exhibit_(WLG-D), Schedule 14.

⁴⁰ See Petersen, page 14, line 14 through page 15 line 2.

1 Because it is written into a contract, Mr. Petersen can tell us precisely the amount (2.85
2 percent) and the effective date (January 1, 2007) for the increase.⁴¹

3 As for the non-union merit increase, if it does occur, it would not occur before
4 March 1, 2007. Mr. Peterson provides estimates that may or may not reflect actual costs.
5 Finally, as with Adjustment 6, it appears that “merit” increases associated with the 11
6 vacant or no longer authorized positions are included. The Commission should disallow
7 this speculative portion of Adjustment No. 10.

8 **Q. Please explain Adjustment No. 15. Contributions and Membership Fees and Dues**

9 A. This adjustment is discussed in our Confidential Section X.

10 **Q. Please explain Adjustment No. 16. Benefit Adjustment**

11 A. This adjustment is also described in the testimony of Mr. Petersen⁴² and Mr. Beyer. In
12 short, Aquila is seeking to increase test year expenses by \$1,498,736 for anticipated, but
13 not yet realized, changes in pension and health-care costs. From the description of the
14 Adjustment, it is clear that these events have neither actually occurred nor are they
15 known. The Commission should disallow this adjustment in its entirety.

16 **Q. Please explain Adjustment No. 18. Postage Costs**

17 A. This adjustment is also described the testimony of Mr. Petersen⁴³ and provides a classic
18 example of why out-of-period adjustments are so inappropriate. Aquila seeks to reduce
19 its overall expenses by \$138,318 related to (1) a decrease in costs related to now
20 discontinued operations offset partially by (2) an increase in costs from an anticipated
21 three-cent increase in postage rates. No such increase has been approved by the Postal
22 Board. In fact, the Postal Commission recently recommended only a two-cent increase in

⁴¹ See Peterson, page 14, lines 19-20.

⁴² See Petersen, page 16, line 3 through page 17 line 7.

1 rates. It is not expected that the Board will act on the Commission recommendation until
2 May 2007, if at all. It is certainly not known and measurable at this point, and at the time
3 of Aquila's filing, it was purely speculative. The Commission should either disallow this
4 Adjustment in its entirety or permit a negative adjustment of \$224,642.72 to reflect the
5 reduction in postage costs from discontinued operations.

6 **Q. Please explain Adjustment No. 19. Insurance Costs**

7 A. This adjustment is also described the testimony of Mr. Siemek.⁴⁴ It combines a number
8 of insurance-related items into one adjustment, increasing costs overall by \$162,521.
9 Aquila's own description of this adjustment describes the cost increases as "forecasted"
10 for 2007. The accompanying workpaper indicates that the forecast is for the calendar
11 year, not the twelve months ending June 30, 2007.

12 It seems clear that these events have not actually occurred and their impact on
13 Aquila's costs are not known. The Commission should disallow this Adjustment.

14 **Q. Which proposed Adjustments does the Public Advocate support?**

15 A. The Public Advocate supports a number of the Adjustments proposed by Aquila in this
16 Rate Case. Several of these adjustments are covered by Public Advocate witness Mr.
17 Albert Bartsch. I will cover the following.

- 18 • Adjustment No. 8. Amortization of rate case expenses. This adjustment of
19 \$166,667 seems reasonable and in-line with past practice. We caution the
20 Commission, however, to note that if this case were to settle, actual expenses may
21 be significantly lower than the amounts included in this Adjustment.
- 22 • Adjustment No. 13. Bad Debt Expense. We do not oppose this reclassification.

⁴³ See Siemek, page 26, lines 3-8.

⁴⁴ See Petersen, page 17, lines 17-21.

- 1 • Adjustment No. 14. Advertising Reclassification. We do not oppose this
2 reclassification, which reduces advertising expenses by \$85,850.
- 3 • Adjustment No. 17. Property Tax expense. This adjustment of \$255,387 appears
4 related to actual property taxes paid no later than September 1, 2006. Therefore,
5 this adjustment would appear to represent a known and measurable expense that
6 has actually occurred.
- 7 • Adjustment No. 20—Raytown Office Building. This adjustment of \$80,014
8 removes the lease cost associated with Aquila’s office space in Raytown,
9 Missouri. This building was vacated in 2006. This adjustment is needed to make
10 the test-year representative of Aquila’s costs going forward, without the inclusion
11 of the now abandoned space.
- 12 • Adjustment No. 21—Graphical User Interface. This adjustment of \$364,515
13 removes the costs allocated to Nebraska for an abandoned project to develop a
14 Graphical User Interface for the utility’s call center. Likewise, this adjustment is
15 needed to make the test-year representative of Aquila’s costs going forward,
16 without the now abandoned GUI application.

1

2 **SECTION VI. CASH WORKING CAPITAL AND LEAD LAG STUDIES**

3

4 **Q. Have you reviewed Aquila's request for cash working capital?**

5 A. Yes, Aquila witness Glenn Dee testified regarding Aquila's working capital requirement.

6 **Q. What is working capital?**

7 A. A business requires a certain amount of capital to operate day to day. The amount of
8 working capital a company needs depends upon its revenue stream and expenses. In the
9 case of Aquila, its working capital consists of inventories of materials and supplies,
10 including gas storage inventories, prepayments, and a cash working capital component.

11 **Q. Why is working capital an issue in the case?**

12 A. Working capital is included in rate base. Ratepayers pay a return to investors on the
13 working capital to the extent the capital is supplied by investors. Aquila reduced working
14 capital for accumulated reserve for deferred income taxes, contributions in aid of
15 construction, ratepayer deposits, and customer advances. Reducing working capital
16 properly recognizes that deferred income taxes, contributions in aid of construction,
17 ratepayer deposits and customer advances are sources of capital available to Aquila that
18 are not supplied by investors and upon which investors should not earn a return.

19 **Q. What is cash working capital?**

20 A. Cash working capital is the amount of cash required by Aquila to have readily available
21 to meet current obligations before cash is received from customers.

22 **Q. How is the cash working capital component of working capital determined?**

23 A. The most commonly accepted method for determining the amount of cash working
24 capital required is a lead lag study. A lead lag study measures the number of days
25 between Aquila's provision of service and receiving payment for the service (lead) and
26 the number of days between the Aquila's incurring an expense and when it pays for the

1 expense (lag). After the lead and lag have been determined, the net of the two (lead
2 minus lag) is applied to the daily expense for each category of expense allowable in the
3 determination of cash working capital.

4 **Q. Did Aquila include an amount of cash working capital in rate base in this case?**

5 A. Yes. Aquila did a lead lag study and calculated an amount of cash working capital to be
6 included for each of the three rate areas.

7 **Q. Did Aquila properly perform the lead lag study?**

8 A. No, they did not. There were sources of non-investor supplied cash that were not
9 included in Aquila's lead lag study.

10 **Q. Please describe the sources of non-investor supplied cash that were omitted from the**
11 **lead lag study.**

12 A. Aquila operates its gas distribution system within the corporate limits of many Nebraska
13 municipalities. Most if not all of these municipalities have negotiated franchise
14 agreements with Aquila. Many of these franchise agreements contain a provision
15 providing for the payment of a franchise fee. Aquila collects this franchise fee each
16 month from the ratepayers within the municipality as a line item on the monthly gas bill
17 and then remits payment of the franchise fee to the municipality required by the
18 franchise. Most municipalities require annual payment, some semi-annual, some
19 quarterly, and some monthly. Aquila has the use of the franchise fee money from the
20 point that the ratepayer pays the fee each month until the fee is remitted to the
21 municipality.

22 **Q. Describe how the collection of franchise fees by Aquila creates a source of working**
23 **capital for Aquila.**

24 A. Exhibit_(WLG-D), Schedule 15, pages 3 and 4 show how the franchise payments provide
25 a source of non-investor supplied funds to Aquila. Information supporting the workpaper
26 was taken from Aquila's Response to data request PA-87 and PA-112, and from our
27 review of the franchise agreements at Aquila's offices on February 27 and 28, 2007.

Schedule 15 assumes that, on average, the franchise fees are paid by ratepayers by the middle of the month following the month they are billed. For cities that require payment by May 31 of the year following collection, the lag in payment by Aquila is 330 days (from mid year in the year of collection to May 31 of the year following, or 180 plus 150 days = 330 days lag). For cities requiring quarterly payments, payments are due by the 30th of the month following the quarter of collection, or mid-quarter (45 days) plus 30 = 75 day lag. Calculations of the various lag periods are contained in Exhibit_(WLG-D), Schedule 15, Page 3.

Q. Are there other non-investor supplied sources of funds available to Aquila?

A. Yes, Aquila also collects city sales taxes in some of cities, and collects state sales taxes in all areas, where it sells gas.

Q. Describe how city and state sales taxes provide a source of working capital to Aquila.

A. City and state sales taxes are very similar to franchise fees. They are collected from ratepayers by Aquila in the monthly billing process and remitted to the municipality or the state by the 25th of the month following collection. A payment lag of 40 days results from mid-month (15 days) plus 25 = 40 day lag. Schedule 15, pages 1 and 2, show the calculations of the cash working capital available to Aquila due to the 40 day lag in the remittance of state and city sales taxes, respectively. Data for this workpaper were taken from PA-113 and PA-114.

Q. When franchise fee collections, state sales tax collections, and city sales tax collections are included in the lead lag study, how is cash working capital impacted?

A. Including franchise fee and state and city sales tax collections in the lead lag study significantly reduces Aquila's cash working capital requirements. As shown on Schedule 15, page 5, Aquila's cash working capital requirement is reduced by \$1,881,354

- 1 **Q.** **What is the effect of this change in cash working capital on rates?**
- 2 **A.** The revenue requirement should be reduced by approximately \$260,000.

1

2 **SECTION VII. AQUILA’S RNA, WNA, AND LCR PROPOSALS**

3

4 **Q. What is the purpose of this section?**

5 A. This section discusses several various policy related proposals made by Aquila in its rate
6 case filing, including its Revenue Normalization Adjustment Rider (RNA), the Weather
7 Normalization Adjustment Rider (WNA), and the limited cost recovery proposal. These
8 proposals were described by Aquila witness Paul H. Raab in his pre-filed Direct
9 Testimony, pages 22 through 84. The first two proposals—the Revenue Normalization
10 Adjustment Rider (RNA)—are described by Aquila as forms of revenue decoupling.

11 **Q. Has the Commission called attention to these policy proposals?**

12 A. Yes, in an order issued February 28, 2007, the Commission identified these three policy
13 proposals Commission and asked its consultant to conduct a study and prepare
14 preliminary recommendations. We understand that the consultant’s study will be
15 available in the next three weeks.

16 **Revenue Decoupling**

17 **Q. What is revenue decoupling?**

18 A. Simply stated, revenue decoupling involves designing utility rates in a manner that utility
19 revenues (and/or profits) are not dependent upon (are decoupled from) the volume of
20 energy sold by the utility. In its most extreme form, revenue decoupling would have the
21 local distribution utility recover 100 percent of its costs through a monthly customer
22 charge, unrelated to the volume of natural gas delivered.

23

1 **Q. Who has promoted the concept of revenue decoupling?**

2 A. The utilities themselves have been among the greatest supporters of the idea, as it would
3 provide more stability and certainty to their revenues and profit streams. Some
4 environmental groups have also supported the idea, in the hope that decoupling revenue
5 from sales volumes would encourage utilities to more vigorously promote conservation
6 and energy efficiency programs. In July 2006, the National Association of Regulatory
7 Utility Commissioners (NARUC) adopted a National Action Plan for Energy Efficiency
8 ("the Plan"), which endorsed the concept of revenue decoupling.

9 **Q. Does everyone support the concept of revenue decoupling?**

10 A. No. For example, many consumer oriented groups vigorously oppose the concept. The
11 Electricity Consumers Resource Council (ELCON) one of the largest and best known
12 industrial customer advocates, recently issued a white paper⁴⁵ on the subject, claiming
13 that revenue decoupling,

14 "disrupts and distorts the utility core business and is not a particularly
15 effective way of promoting energy efficiency or anything of benefit to
16 consumers."

17
18 A number of consumer advocates in other states have disagreements with revenue
19 decoupling, as we will discuss below in the case of Iowa.

20 **Q. Aquila mentions that many states have implemented such measures. What is the**
21 **track record of revenue decoupling?**

22 A. Revenue decoupling has yet to develop a recent track record. Past efforts have proven
23 less than successful.

⁴⁵ ELCON, Revenue Decoupling: A Policy Brief of the Electricity Consumers Resource Council, January 2007. Available at the ELCON website at www.elecon.org. The white paper begins with an epigraph, attributed to H.L. Menchen, "Every complex problem has a simple solution to good too be true, and it usually is."

1 According to a 2006 study conducted by the Alliance for an Energy Efficient
2 Economy (ACEEE),

3 “We found that despite the surging interest in regulatory decoupling,
4 there are thus far relatively few cases where such an approach has been
5 enacted and effectively implemented for a sufficient period of time to
6 begin to assess the results. The states of Oregon and California are the
7 primary leading examples. We also found a small set of cases in
8 which the decoupling has been enacted on a “pilot” or other more
9 limited basis, but there has not been sufficient experience to observe
10 possible effects on energy efficiency activity. These examples include
11 Maryland, New Jersey, North Carolina, and just recently, Ohio.
12 Lastly, we identified several other states that are actively considering
13 such an approach, including Idaho, New York, and Washington.”⁴⁶
14

15 **Q. What is your position on the issue of Revenue Decoupling?**

16 A. While open to changes in rate design, I am opposed to the specific proposals made by
17 Aquila in this docket, for a number of reasons, which are described below. However, I
18 note that, in 2006, both Aquila and Kinder Morgan have made proposals in general rate
19 cases that move in the direction of revenue decoupling. No doubt other utilities and
20 stakeholders would have views on the subject. We believe that the impacts, intended and
21 otherwise, of these proposals have policy implications far beyond the result of a single
22 rate case. I would not be opposed to the Commission investigating this issue in a generic
23 docket, along the lines of what the Iowa Utilities Board has undertaken (described below)
24 in the past year.

25 **Q. What problems does revenue decoupling create?**

26 A. The problems created by revenue decoupling mechanisms are many. I will discuss just a
27 few of them here.

⁴⁶ Martin Kushler, et. Al. “Aligning Utility Interests with Energy Efficiency Objectives: A Review of Recent Efforts at Decoupling and Performance Incentives. American Council for an Energy Efficient Economy (ACEEE) Report No. U061, October 2006, p. iii.

- Reduces incentives for customers to conserve energy
- Increases customer-borne risk
- Provides more certainty for utility benefits than customer benefits
- Makes rates more volatile and unpredictable
- Reduces incentives for utility performance
- Expands single issue ratemaking
- Increases the burden on regulators and customers

Q. Revenue Decoupling is being sold as a way of providing incentives to *utilities* to promote conservation. What conservation incentives does revenue decoupling provide to *customers*?

A. Noted regulatory author Alfred E. Kahn is credited with the phrase, “all regulation is incentive regulation.” Oddly enough, from the customer standpoint, revenue decoupling reduces incentives to conserve. For example, if a homeowner were to turn down the thermostat during a cold winter to conserve fuel, under current rate design, he or she would save on both the commodity cost of natural gas and on the volumetric charge for local delivery. If such volume-based local charges were eliminated or substantially reduced, the incentive to conserve would also be reduced. Even further, proposals such as Aquila’s RNA, would *increase* a customer’s bill, as successful conservation efforts would result in a rate increase to compensate utilities for lost sales.

ELCON’s President, John Anderson uses even stronger language describe this disincentive for conservation,

“But to believe that very many consumers will undertake conservation or energy efficiency efforts without being rewarded with lower bills is somewhere between counter-intuitive and ludicrous.”⁴⁷

⁴⁷ See ELCON Press Release, March 1, 2007.

1 Q. **What effect does revenue decoupling have on who bears risk?**

2 A. The Commission should understand that revenue decoupling fundamentally alters the
3 decades-long bargain between utility and customer. It shifts all risk from the utility to
4 another constituency (customers), who are least capable of managing such risk.
5 Decoupling removes incentives for utilities to perform their traditional role: delivering
6 fuel to homes and businesses safely and reliably. Finally, decoupling raises fundamental
7 questions about utility structure and ownership not addressed in decades. The
8 Commission will be well served to have the explicit backing of the Legislature, if such a
9 path is ever taken in Nebraska.

10 Q. **In balancing interests between the utility and ratepayers, how likely is it that the**
11 **utilities will realize benefits versus the consumer?**

12 A. The potential benefits touted for revenue decoupling will likely be realized by utilities.
13 However, benefits to consumers are either unlikely to be realized or can be achieved
14 more easily in less disruptive ways. On balance, the proposal favors utilities far more
15 than ratepayers.

- 16 • Stabilize revenue for the utility. Aquila's RNA proposal will certainly provide
17 revenue stabilization to the utility. While this proposal obviously favors utilities,
18 it is not clear whether or how consumers would also share in any tangible benefit.
19 Presumably, a utility with a more stable revenue stream would be able to raise
20 capital at a lower cost. If so, the Commission would need to explicitly design a
21 mechanism to transfer a portion of the lower capital cost back to the ratepayer.
22 Otherwise, the utilities will receive a windfall: get paid more (in higher than
23 otherwise revenue) to do less (by assuming a lower level risk).

1 However, the Commission should keep in mind that stability comes at a
2 cost for customers and for conservation. Customers will be paying more during
3 periods of low usage and less during periods of high usage, diminishing the strong
4 price signals sent by commodity prices.

- 5 • Eliminates disincentives to utility-driven conservation efforts. This benefit may
6 or may not be realized and again it is also cast from the point of view of the
7 utility. “Revenue normalization” may eliminate a utility’s concern about
8 conservation efforts, but as we have shown above, it reduces a consumer’s
9 incentive to save energy and to use the lowest cost fuel.

10 By eliminating the link between sales volumes and revenues, we fear that
11 it will increase incentives for utilities to promote fuel switching and engage in
12 gamesmanship. As for fuel switching, under these proposals, which adjust for
13 customer growth, the utility has every incentive to add customers, regardless of
14 whether any additional throughput occurs. Logic suggests that utilities will work
15 aggressively to recruit customers from other fuels (electric, propane, or oil) as
16 every new customer added between rate cases adds to profit, as the per customer
17 revenue figure is not updated.⁴⁸ Going further, utilities will have incentives to
18 game the system, adding more than one “customer” per location to maximize
19 revenue from customer charge and the RNA Rider. By merely adding meters to
20 the system and sending more bills, utilities can increase revenue without actually
21 delivering more product.

⁴⁸ I believe that this sort of effect is what Jim Lazar described as a “flawed mechanism.” Mr. Lazar’s work is described in additional detail below.

As an example of gaming: consider the case where an office complex is served with multiple services, but billed on a single invoice. Could not the utility move the metering point from a single point on the main to multiple points, one along each service. Then the utility could send multiple bills, collecting multiple customer charges, and also drive down the revenue per customer (driving up the RNA adjustment)?

Q. How does revenue decoupling increase rate volatility?

A. Specific proposals to implement revenue decoupling, such as Aquila's WNA and RNA proposals, typically involve monthly changes to rate elements (local delivery or customer charges) that have typically changed only after rate cases, every few years or so. These frequent changes in rates add to the already considerable volatility in other rate elements, such as the purchased gas adjustment.

Furthermore, these price changes will work counter to the natural price signals sent by the commodity market. During cold winters, commodity prices will be high and usage will be high, providing ample incentive for consumers to conserve. However, if a WNA or RNA mechanism then reduces rates in an effort to credit back to customers a utility's revenue windfall, then the strong commodity price signal will be dampened. Perversely, this dampening of the price effect during cold winters is the sole benefit to customers claimed by Aquila for its RNA proposal

By increasing the costs consumers pay regardless of usage and reducing the price per unit used, such rate designs lessen the rewards—and thus the incentives—for conservation. The economic law of demand holds that the lower the price, the higher the quantity demanded, all else being equal.

1 **Q. What effect may revenue decoupling have on a utility’s incentive to perform?**

2 A. Under current regulatory approaches and prevailing rate designs, natural gas local
3 delivery companies (LDCs) have a strong incentive to perform: namely, if they do not
4 deliver product to consumers they do not collect revenue. So, any system outage will be
5 met with a swift response as each hour offline the lost revenues mount.

6 The stated goal of the utilities promoting revenue decoupling is to reach a point
7 where the utility is indifferent as to whether gas is used or not used by its customers.

8 With a high enough fixed charge, a utility would cover all of its non-incremental costs
9 without actually delivering a single MCF of fuel. If we reach that point, the law of
10 unintended consequences would hold that the utility will really not care whether it
11 delivers any gas. The LDC will become little more than a taxing authority: collecting its
12 increasingly arbitrary fixed costs without regard to performing its once primary role of
13 distributing fuel to homes and businesses.

14 Some promoters of the idea imply that revenue decoupling provides incentives for
15 management to minimize costs, as they are no longer concerned with reductions in sales.

16 Let us be clear about the costs that utilities will attack first. Indifferent about actually
17 distributing gas, utilities will seek to cut costs in any area touching the delivery of
18 product: most importantly, maintenance and investment in plant and equipment and
19 operation of the system.

20 **Q. Would Revenue Decoupling expand piecemeal ratemaking?**

21 A. Yes. Revenue decoupling is a prime example of “piecemeal” or “single issue”
22 ratemaking. As is the case with the limited cost recovery proposal, we are concerned

1 about the further expansion of this regulatory approach, as we believe that it ill serves the
2 interests of consumers, regulators and the utilities themselves.

3 In our view, the traditional rate case process has served both consumers and
4 utilities reasonably well over the decades. Here in Nebraska, it has been a mere four
5 years since the introduction of statewide natural gas regulation. This case marks the
6 beginning of only the second round of rate cases for the state's three investor-owned
7 distribution utilities. We hardly think that now is the time to abandon the entire system
8 and go in a radical new direction.

9 Although no substitute for actual competition, regulation through the traditional
10 rate case allows regulators to balance the interests of utilities and consumers, with the
11 benefit of having the complete picture in front of all participants.

12 In contrast, piecemeal ratemaking, by its nature, is biased against the consumer.
13 In practice, only those single issues of interest to the utility are brought before regulators,
14 while issues of interest to consumers are ignored. We urge the Commission not to further
15 expand piecemeal ratemaking.

16 **Q How would revenue decoupling increase regulatory workloads and administrative**
17 **burdens?**

18 **A** Rather than speculate, let me illustrate how revenue decoupling could increase regulatory
19 workloads with a real example. Aquila's RNA Rider proposal will require a monthly
20 adjustment, and "the workpapers detailing the RNA adjustment will be forwarded to the
21 Commission Staff at least ten days prior to the start of the billing cycle where it will be
22 applied."⁴⁹ Now the Commission, Staff, and intervenors will get the opportunity to spend

⁴⁹ Petersen Direct Testimony, p. 26, lines 2-8.

1 up to one-third of each month with a mini-rate case determining what rates will be
2 charged for usage two months prior.

3 Furthermore, as we will discuss below, because of the Aquila-described “key
4 element” of the customer growth adjustment, parties will feel obligated to argue over
5 every single expansion project undertaken by the utility and every customer addition, as
6 each has the potential to raise rates for all existing customers. Revenue decoupling’s
7 promised reduction in rate cases represents nothing more than false economy.

8 Of course, yet another monthly adjustment will produce the attendant increase in
9 administrative costs. Presumably, these additional costs will be built into customer rates,
10 further increasing the burden on ratepayers.

11 **Q. What were the results of Iowa’s investigation into revenue decoupling?**

12 A. In February 2006, the Iowa Utilities Board (IUB) opened an “Inquiry into the Effect of
13 Reduced Usage on Rate Regulated Natural Gas Utilities.”⁵⁰ The Iowa Board thoroughly
14 examined the subject, receiving comments on the topic in February 2006, hosting a
15 workshop in May 2006, and receiving two additional rounds of comments in August
16 2006.⁵¹

17 On December 18, 2006, the Board closed its inquiry without taking any action.
18 The Iowa Board did not find “a substantial problem in Iowa” with utilities’ ability to earn
19 their authorized rate of return. The Board also did not detect any consensus among
20 parties building around any one decoupling method. The Board’s decision is particularly
21 noteworthy in that Diane Munns, the President of NARUC at the time of the adoption of

⁵⁰ Iowa Utilities Board Docket No. NOI-06-1.

⁵¹ This witness participated in the Iowa Board’s docket, filing comments on behalf of another client. Some of this testimony has been adopted from those comments. Aquila also participated in the Docket.

1 the Plan, was also a Board Member of the IUB at the time they declined to introduce
2 revenue decoupling.

3 A number of parties participated in the Inquiry. Iowa's Office of Consumer
4 Advocate (OCA), filed extensive comments that the Commission would find
5 illuminating. The OCA's August 10, 2007, comments⁵² are particularly helpful, in that it
6 does an excellent job of framing the issue of balancing the interests of consumers and
7 utilities. Some of the highlights of the OCA's comments include the following:

- 8 • "A rate regulated utility is not insulated from normal business risks under
9 traditional regulation."
- 10 • "The financial health of some regulated utilities is increasingly under pressure
11 due, not to ordinary business risks inherent to natural gas utilities, but to poor
12 business performance of non-regulated affiliates."
- 13 • "It is essential to achieve an equitable balance between investor and consumer
14 interests."
- 15 • "...the burden of providing a steadier source of revenues to the utilities through
16 the rate design mechanisms under consideration would likely fall heaviest on
17 those least able to bear this burden..."
- 18 • "OCA's analysis of Iowa gas utility data indicates that moderate reductions in
19 usage do *not* result in major losses of earnings for Iowa LDCs.

20 **Q. What purported problem is revenue decoupling trying to solve?**

21 A. At this point, it may help everyone to recall why natural gas utilities are rate regulated in
22 the first place. Concerned that the provision of natural gas service represented a "natural

⁵² OCA Response, pp. 1-6.

monopoly,” governments began to regulate the behavior of such utilities,⁵³ which otherwise would have an incentive to set prices above and produce output below, what would otherwise result from a competitive market.⁵⁴ Thus regulation began as an effort to protect consumers from unregulated monopolies.

The distinguishing characteristic of natural monopolies is the economies of scale and scope, which result in declining average costs.⁵⁵ As Phillips writes, “The inherently noncompetitive market structure, therefore, is determined by economies of scale (of the long-run variety) and/or economies of scope.”⁵⁶

This cost advantage may provide monopolies with the ability to restrict output and raise prices, but they are not immune from general market forces and business conditions in the general economy. Microsoft Corporation is thought to have monopoly power over the sale of operating systems for personal computers, if not also for the sale of popular business software packages. Yet even powerful Microsoft is not immune from the vagaries of the business cycle or competition from substitute goods, immunity that Aquila is seeking under these proposals.

Q. Is revenue decoupling a new idea?

A. No. The concept behind revenue decoupling has been around for decades. A number of states have tried various methods of loosening the ties between revenue, sales, and profits in an effort to promote conservation efforts by utilities. To use the most charitable word possible, the results have been mixed. Here are a few examples of past efforts:

⁵³ See Lipsey, Richard G. et al., *Economics*, Seventh Edition, Harper & Row, New York: 1984, p. 308.

⁵⁴ See Phillips, Charles F. Jr., *The Regulation of Public Utilities: Theory and Practices*, Third Edition, Public Utilities Reports: Arlington, VA 1993, pp. 62-63, See Figure 2-5.

⁵⁵ Phillips, p. 52.

⁵⁶ Phillips, p. 53.

- 1 • Maine: Central Maine Power. In a Briefing Paper by Ken Costello of the National
2 Regulatory Research Institute, he sites the experience of Maine in the early 1990's.
3 In my view, this example is illustrative of the unintended consequences of even the
4 most well-intentioned efforts to decouple revenue from sales, and I hope the
5 Commission will indulge this lengthy quote:

6 “In Maine, lower sales levels in the early 1990s caused by an economic
7 recession (in the previous rate case, the sales forecast was substantially too
8 high) led to substantial revenue deferrals that Central Maine Power was
9 ultimately entitled to recover under its revenue decoupling mechanism
10 (“Electric Revenue Adjustment Mechanism”). The utility did not recover
11 these deferrals, however, because of an agreement with parties to avoid
12 immediate rate increases during bad economic times. By the end of 1992,
13 the revenue deferrals had reached \$52 million. Observers argued that only
14 a small portion of this amount was the result of the utility’s conservation
15 efforts and that the vast majority of deferral, instead, resulted from the
16 economic recession. **There was the general perception that the revenue
17 decoupling mechanism shielded the utility against the financial
18 consequences of the recession, rather than providing the intended
19 conservation incentive impact.** Termination of the RD mechanism
20 occurred in November 1993. (See, for example, Maine Public Utilities
21 Commission, Report on Incentives Mechanisms for the Promotion of
22 Energy Efficiency and System Reliability, presented to the State
23 Legislature, Feb. 1, 2004.)”⁵⁷ (Emphasis added.)
24

- 25 • Minnesota: Lost Margin Recovery. Minnesota’s natural gas and electric utilities
26 have already “been there/done that” in terms of recovery of lost margins resulting
27 from conservation efforts. In the late 1990’s, lost margins began to total in the
28 millions of dollars, driving utility earnings above authorized levels. The state’s
29 Public Utilities Commission then attempted to regulate the overearning, but were
30 struck down by that state’s Court of Appeals.⁵⁸ In the end, the Minnesota

⁵⁷ Costello, Ken. Briefing Paper 06-06, “Revenue Decoupling for Natural Gas Utilities,” The National Regulatory Research Institute, April 2006, p. 29, and footnote 59. This Briefing Paper is available on the internet at <http://www.nrri.ohio-state.edu/nrri-pubs>.

⁵⁸ State of Minnesota Court of Appeals, December 19, 2000, Unpublished Opinion in Case Nos. C2-00-456 and C4-00-457, pp. 7-8. This Opinion is available on-line at <http://www.lawlibrary.state.mn.us/archive/> index.html.

Commission scrapped the whole lost margin system, replacing it with a performance-based conservation incentive.

- Washington: Puget Power's Periodic Rate Adjustment Mechanism (PRAM).

Implemented in 1991 and discontinued in 1995. This experiment was not considered to be a success by many observers.

Revenue Normalization Adjustment Rider (RNA)

Q. What need does Aquila claim is driving this proposal?

A. Aquila claims that “volumetric changes faced by Aquila have unnecessarily stressed its finances.”⁵⁹ However, it should be noted that *Moody's Investors Service* attributes Aquila's stressed finances to a much different root cause,

“In recent years the company has focused its efforts on reducing leverage and improving its credit profile following a severe weakening of its business and liquidity in 2002/2003 due to its interests in unregulated energy and trading operations.”⁶⁰

Standard & Poor's adds that, “Over the last two years, the company has worked to stem material cash losses by exiting its noncore businesses and terminating its tolls and gas contracts.”⁶¹

Q. How does Aquila's proposal address this alleged need?

A. Aquila claims that,

“The RNA Rider is a billing adjustment factor computed on a monthly basis that creates a credit or charge to the monthly delivery charge for firm customers. As the name suggests, the mechanism adjusts for the level of revenues received in a particular month. The mechanism is designed to

⁵⁹ See Petersen's Direct Testimony, p. 23, lines 7-8.

⁶⁰ Moody's Investors Service: Global Credit Research, report on Aquila, Inc. December 2006. Page 1. This report was provided to the Public Advocate by Aquila in response to Data Request PA-12.

⁶¹ Standard & Poor's RatingsDirect. Report on Aquila, Inc. Published October 31, 2006. Page 2. This report was provided to the Public Advocate by Aquila in response to Data Request PA-12.

1 stabilize the level of revenues that are provided by customers to the
2 Company each month.”⁶²
3

4 **Q. Strictly speaking, is the RNA proposal revenue decoupling?**

5 A. No. Strictly speaking, the RNA proposal does not represent revenue decoupling. It
6 maintains the same underlying rate design and merely attempts to adjust utility revenue
7 up or down to meet utility goals.

8 At least one commentator has suggest that the necessary elements for a “fair and
9 effective decoupling include the following,

- 10 • “Significant commitment to energy efficiency investment
- 11 • Progressive rate design that keeps fixed rate elements low (or zero.)
- 12 • A “collar” on rates – no more than X% change in a year. Additional
- 13 amounts deferred
- 14 • Scheduled periodic rate cases: 3-5 years
- 15 • Capital Structure Adjustment if weather risk is shifted to customers”⁶³
16

17 None of these elements appear as part of either Aquila’s RNA or WNA adjustment.

18 **Q. Does Aquila’s proposed RNA rider reflect the utility’s increasing economies of**
19 **scale?**

20 A. No. The RNA rider, as proposed by the utility does not reflect the utility’s increasing
21 economies of scale. As previously mentioned, the basis for the rate regulation of natural
22 gas distribution utilities is that they are natural monopolies. The distinguishing
23 characteristic of natural monopolies is that they exhibit increasing returns to scale so that
24 a single firm would serve the market most efficiently.

25 As a natural monopoly adds customers, its fixed costs are spread over more
26 customers, lowering the average cost per customer. Aquila’s RNA proposal allows the

⁶² Petersen, p 22, lines 3-8.

1 utility to pocket these efficiency gains, as adding new customers merely raises the bar,
2 dollar for dollar, for what the utility is entitled to recover. This perverse incentive, rather
3 than encouraging conservation efforts by the utility, merely encourages them to add new
4 customers at a breakneck pace

5 Somehow, Aquila attempts to sell this aspect of the plan as a *feature* claiming,

6 “By adjusting for the number of customers that have been added
7 on a net basis, it provides greater confidence that the resulting
8 revenue benchmark is reflective of current conditions.”⁶⁴
9

10 Greater confidence for whom? One of the features of traditional rate cases is that
11 customers added between rates cases provide additional revenue and profit for the utility,
12 perhaps postponing the next rate case. Under Aquila’s proposal, each month is a new
13 rate case, except the revenue requirement is increased with new customers, but the per
14 customer revenue number remains fixed.

15 **Q. Is a fixed revenue per customer amount a feature of all revenue decoupling**
16 **proposals?**

17 A. No. Jim Lazar reports that recent revenue decoupling proposals explicitly recognize that
18 “New customers are cheaper to serve and the line extension policy makes the company
19 whole if costs exceed revenues.”⁶⁵ One proposal “allows current revenue/customer level
20 for existing customers. Lower level for new customers”.

⁶³The Regulatory Assistance Project (RAP), May 24, 2006 presentation to the Minnesota Public Utilities Commission. Slide Page 40. Presentation available online at www.raponline.org/Slides/MNDecouplingMay06.pdf.

⁶⁴ Raab, p. 27, lines 1-4.

⁶⁵ Lazar presentation “Examples of Good, Bad, and Ugly Decoupling Mechanisms” to NARUC Symposium: Aligning Regulatory Incentives with Demand Side Resources, August 2, 2006. Slide no. 13. Presentation available on-line at www.mtpc.org/RenewableEnergy/public_policy/DG/resources/2006-08_NARUC_Lazar_Decoupling-Mechanisms.pdf

1 **Q. Aquila describes a “weather normalization” component of the RNA. Where in the**
2 **RNA formula is this component to be found?**

3 A. Aquila does refer to a “weather normalization” component of the RNA. The RNA rider
4 mechanism does not explicitly adjust for weather variations. Instead, it adjusts implicitly
5 for any factor that produces a reduction in per customer revenues. Warmer than
6 anticipated weather may be one such factor. General economic conditions could be
7 another. However, one factor could be Aquila’s imprudent additions of multitudes of
8 new, low-use customers. Finally, the per customer revenue figure could simply have
9 been mis-calibrated in setting the rates.

10 **Q. Company witness Raab lists seven arguments against RNA-type mechanism. Do**
11 **you agree with his testimony?**

12 A. No. I do not agree with Mr. Raab’s characterization of arguments against RNA-type
13 mechanisms. First of all, there are many more than seven arguments that have been made
14 against RNA-type mechanisms.

- 15 • Special circumstances. Aquila has made no such showing of special circumstances.
16 All the utility has done is to make two claims, and then to depend on a logical fallacy
17 to link them to the RNA mechanism.

18 In the first claim, Aquila alleges that average usage has fallen eleven percent.
19 By itself, a falling average usage number proves nothing. What we need to know is
20 ‘how do declining usage and increasing customer counts translate into an overall
21 revenue impact and revenue per customer?’ Next we need to know ‘how do declining
22 usage and increasing customer counts translate into an overall cost change and change
23 in cost per customer.’ Only by determining these facts can we assess the overall

1 impact, if any, on profit. After all, the ultimate goal of ratemaking is to ensure just
2 and reasonable rates for the customer and a reasonable return for the utility. Is this
3 usage decline impacting the utility's bottom line return or not? We cannot determine
4 from the record thus far. As it stands, the utility provides no information on how the
5 per customer revenue has fared in that time, the key metric in designing the RNA
6 rider mechanism.⁶⁶ Lazar documents where lower use by new customer was the
7 "biggest driver" in declines in average customer usage.⁶⁷

8 Second, the utility shows how many millions more in revenue they could have
9 achieved under an Aquila designed RNA. No mention in made as the cost impact of
10 the new customers. It may well be the case that, given declining costs per customer,
11 under normal weather and other conditions, the utility is able to still earn a just return
12 and the RNA would merely allow for windfall profits.

- 13 • Adjusting revenues between rate cases without adjusting costs. Here Mr. Raab
14 completely ignores the issue of declining costs per customer, framing the issue as one
15 of volume only. As for the volume effect, while it is true that, in the exercise of
16 adjusting test year revenues for weather normalization, one does not alter costs, that is
17 only because the per unit volume costs are adjusted elsewhere in the cost of service.
18 Mr. Raab's response to this argument misses the mark in every aspect.
- 19 • Lower likelihood of addressing real problems. This argument is a complete straw
20 man. Who, exactly, is making this argument? To be charitable, this argument sounds
21 like a person opposed to RNA mechanisms, not because they are bad policy, but they
22 do not go far enough to implement true revenue decoupling. To be less charitable,

⁶⁶ The utility, obviously, provides no discussion on what role aggressive expansion into outlying, low-fuel use areas may have played on this apparent decline in per customer usage.

1 presenting this argument seems to be little more than an opportunity to present as
2 conclusory statements claims about the utility's "real problems."

- 3 • Unequal distribution of benefits between utility and consumers. Again, Mr. Raab
4 presents no evidence and certainly no quantification of any benefits accruing to
5 consumers and does not address the "fixed, per-customer revenue" flaw in the
6 mechanism, which directs the benefits of customer additions toward the utility and
7 away from existing customers. Mr. Raab further confuses the issue by conflating
8 revenues and costs⁶⁸ and failing to note that, through the customer growth adjustment,
9 required revenues continue to increase, with no adjustment for overearnings.
- 10 • Upward pressure on short-term rates. Here, Mr. Raab concedes this point. However,
11 the Commission should note that no quantification of this amount has been attempted.
12 No cost / benefit analysis has been performed by Aquila to show that 'these benefits
13 will accrue to ratepayers, these benefits are worth so many dollars to ratepayers, and
14 to get these benefits, ratepayers need pay only so many dollars more.'

15 Instead, we get, to the dollar (\$4,176,558) an estimate of how many more
16 millions in revenue could have collected had this mechanism been in place earlier.⁶⁹
17 However, he does not show the resulting effect on earnings from this additional
18 revenue.

- 19 • Overly broad solution. Perhaps inadvertently, here Mr. Raab strikes at one of the
20 most serious flaws of his proposal. He has, thus far, presented the problem in terms
21 of the utility's finances, its ability to earn profits "consistent with the Commission's
22 authorized returns." However, his mechanism adjusts only revenues, as it contains no

⁶⁷ Lazar, Slide 13.

⁶⁸ Petersen, page 47, lines 2 through 3.

1 cap or other limit on the utility's profits, which, given the declining cost nature of the
2 business, should only increase under this mechanism.

- 3 • Should be Accompanied by a reduction in ROE. Mr. Raab's views notwithstanding,
4 nearly every analyst of this problem has recognized the risk reduction properties of
5 such mechanisms. Lazar reports on a recent proposal that contains "explicit
6 recognition of capital impacts benefits associated with weather decoupling"⁷⁰

7 Mr. Raab suggests five (actually only four) reasons why ROE should not be
8 reduced with RNA implementation,

- 9 1. Risk management strategies. I must confess that I do not understand this reason.

10 Is Aquila implying that it will no longer practice risk management?

- 11 2. Inability to measure (1). It may well be difficult to measure impact on ROE, but I
12 would vigorously take issue with Aquila's observation about ROE bandwidth.

- 13 3. Inability to measure (2) This reason repeats number 2. Mr. Raab claims that,

14 "No one has been able to develop a defensible measure of the impact
15 that such a mechanism has on ROE. And, it could be positive (less
16 revenue risk) or negative (the uncertainty associated with a rate
17 increase)."⁷¹

18
19 At least one utility analyst has been willing to give it a go. Dr. Roger A.
20 Morin, testifying on behalf of the Chattanooga Gas Company (CGC), has
21 ventured a guess as to what the risk premium reduction should be. In that utility's
22 current rate case, Dr. Morin testified as follows,

23 "It is my opinion that a just and reasonable return on common equity
24 ("ROE") for CGC at this time is 11.5%. If the Company's proposed
25 Conservation and Usage Adjustment rider (CUA) and Pipeline

⁶⁹ In just the first half of 2006. Raab, p. 27, lines 21-22.

⁷⁰ Lazar, slide 14.

⁷¹ Raab, p. 48, lines 19-21.

1 Replacement Program (PRP) mechanism are approved, it is my
2 opinion that a just and reasonable ROE for CGC is 11.0%.”⁷²
3

4 Later, Dr. Morin elaborates on his recommendation,

5 “If the proposed CUA and PRP mechanisms are approved, the
6 Company’s risk will be reduced, and the cost of common equity
7 capital likely will decline by some 50 basis points from 11.5% to
8 11.0%. This assessment is based on bond yield differentials and beta
9 risk differentials, as discussed above.”⁷³
10

11 While not necessarily endorsing his conclusions, we believe Dr. Morin’s
12 work demonstrates that estimating the risk reduction of revenue decoupling
13 mechanisms can be done.

14 4. Too far removed from the test year. If that were the case, the RNA itself could be
15 implemented much beyond the end of the test year. The RNA mechanism will
16 continue to adjust some elements of the cost of service but not others. How does
17 Mr. Raab justify other automatic adjustments, such as the PGA, that continue
18 years after a test year has been filed?

19 5. Bad public policy. How much would a consumer pay to get “more stable bills”
20 through time? Putting aside the questions as to whether bills would actually be
21 more stable or less stable under these proposals, Aquila already offers utility
22 budget billing and fixed rate programs. It is not clear what the RNA offers in
23 terms of stability not offered by these other programs.

24 How much would a consumer pay for a more financially sound utility?
25 The answer should be “nothing,” because a more financially sound utility should
26 have a lower cost of capital and thereby a reduced cost to its customers.

⁷² Prepared Direct Testimony of Dr. Roger A. Morin. Before the Tennessee Regulatory Authority. IN RE: Chattanooga Gas Company. June 30, 2006. Page 4, lines 8-12.

1 How much would a customer pay for a utility to have greater incentives to
2 promote energy efficiency? As discussed above, Minnesota found a way to
3 provide incentives and reward utility led conservation efforts directly.

4
5 Receiving little attention are the customer conservation disincentives, perverse incentives
6 on system maintenance and reliability, Commission workload, or the many other
7 difficulties discussed in this section.

8 **Q. Aquila witness Raab describes revenue decoupling in his testimony. Do you agree**
9 **with his assessment?**

10 A. Mr. Raab includes general discussion on the topic of revenue decoupling in his
11 testimony (pages 28 through 43) touting the advantages of the concept. Rather than rebut
12 Mr. Raab line by line, I would point out that the vast majority of this commentary has
13 little to do with the specifics of his proposal. I may have more to say on this general
14 topic in response to the Commission consultant's report.

15 In the meantime, I would like to make the following observations regarding Mr.
16 Raab's discussion of revenue decoupling:

- 17 • Some benefits accrue only to pure revenue decoupling mechanisms. Mr.
18 Raab describes a number of alleged benefits of revenue decoupling and
19 "RNA-type mechanisms." What he fails to do is to explain how his
20 specific RNA Rider proposal can deliver these benefits. As described
21 above, the Aquila RNA proposal is not "pure" revenue decoupling.

⁷³ Dr. Morin, p. 54, lines 3-6.

- Commissions usually demand a *quid pro quo*. Mr. Raab mentions proposals by New Jersey Natural Gas and South Jersey Gas.⁷⁴ The New Jersey Board of Public Utilities approved these programs,⁷⁵ and these are just some of the conditions placed:
 - o The programs are pilots, lasting three years
 - o The companies shareholders will pay for enhanced conservation programs. New Jersey Natural Gas is to pay \$2,000,000 up front, and South Jersey Gas is to pay \$400,000 a year. Any cost overruns are to be borne by the utilities.
 - o The utilities had to abandon other proposals
- No serious discussion of the downsides. Notwithstanding Mr. Raab's straw men arguments in opposition, studies of actual mechanisms have focused on the potential for gaming, deterioration in service quality, and effects on customer-led conservation, among other potential drawbacks.⁷⁶

WNA Clause

Q. How does the WNA differ from the RNA?

A. Because the Weather Normalization Adjustment is, in some respects, a subset of the RNA, it is less pernicious. By adjusting for only weather deviations, for example, it avoids the pitfalls found in the Central Maine example, where the utility was shielded from more general business risks. However, all of the other flaws inherent in RNAs are

⁷⁴ Raab, p. 35, line 11.

⁷⁵ See Order issued in Docket Nos. GR05121019 and GR05121020, on December 12, 2006.

⁷⁶ For one example of such studies, see the study by Daniel G. Hansen and Steven D. Braithwait of Christensen Associates, "A Review of Distribution Margin Normalization as Approved by the Oregon Public Utility Commission for Northwest Natural," March 31, 2005.

1 present: discouraging customer conservation, dampening price signals, increasing
2 administrative costs, etc.

3 More significantly, the fatal flaw with weather normalization adjustments is that
4 they shift risks onto customers that could more easily be managed by the utility. In other
5 words, they impose a second best solution onto a problem for which a first-best solution
6 is readily available.

7 A number of markets have arisen to provide weather futures, hurricane futures,
8 and other weather-related derivative instruments. Few jurisdictional customers would
9 have the sophistication to manage such mitigation measures and none would be able to
10 justify the administrative and transactional costs. However, a large utility like Aquila or
11 Black Hills would have the wherewithal to do so.

12 **Q. What is one of the problems with the specific elements of Aquila's WNA proposal?**

13 A. Aquila proposes to calculate the adjustment on a customer specific basis. For new
14 customers added to the system, the factor does not appear to recognize the additional
15 revenue they provide. As such, it will tend to over estimate the amount of revenue
16 needed to make the utility whole for variations in weather.

17 **Q. Please describe the components of a natural gas revenue stabilization plan that
18 would be reasonable or necessary.**

19 A. Notwithstanding our opposition to any natural gas revenue stabilization plan, if the
20 Commission would determine that such a plan should be considered, the following
21 additional components should be included:

- 22 • Tracking of outages and availability statistics, with financial penalties for failing
23 to meet minimum standards

- Recognition of declining costs and an expected improvement in operating efficiency
- Minimum investment levels for maintenance and capital renewal
- A mechanism for passing reduced capital costs to consumers
- Mandatory rate cases at regular intervals
- A strict limit to prevent overearning

Limited Cost Recovery

Q. Have you reviewed Aquila's request for a Limited Cost Recovery mechanism?

A. Yes, Aquila witness Vern Siemek testified in support of Aquila's request for a Limited Cost Recovery mechanism.

Q. Please explain Aquila's Limited Cost Recovery (LCR) proposal.

A. Aquila's LCR proposal provides for annual, minimal review revenue increases that Aquila contends (but does not assure) would reduce the need for larger, periodic general rate cases.

Q. How does the LCR accomplish the annual revenue increases?

A. Aquila proposes to apply the CPI-U to increase certain specified categories of costs with a cap on any annual increase set at 50% higher than the average of the CPI-U for the preceding four years. Aquila proposes to file an annual LCR notice letter by October 1 of each year, indicating the planned increase in revenues to become effective on January 1 of the following year, with the notice letter percentages based upon the most recent CPI-U information.

Q. Have you reviewed the Commission Order in Docket No. NG-0031?

1 A. Yes. In that Docket, Aquila proposed an LCR mechanism and the Commission found
2 that an LCR would increase Aquila's overall revenue requirement, and that overall
3 revenue requirements may only be changed in a Section 66-1838 general rate filing. On
4 that basis, the Commission denied Aquila's request for an LCR.

5 **Q. Does the filing in this case satisfy the Commission's concerns expressed in that**
6 **Order regarding a lack of statutory authority to raise overall revenue requirements**
7 **outside of a general rate case?**

8 A. No. Although Aquila is making its LCR request in a general rate case, each of the annual
9 LCR filings would effect an increase the Aquila general revenue requirement outside a
10 general rate case. The Nebraska State Natural Gas Regulation Act (LB 790) has not
11 been amended since the Commission's Order in NG-0031. Section 66-1802 still defines
12 a "general rate filing" as any filing which requests changes in overall revenue
13 requirements. The Section 66-1808 rate change process expressly does not apply to
14 general rate filings, while the Section 66-1838 general rate change process expressly
15 applies only to general rate filings. The Public Advocate is of the opinion that the
16 Commission does not have the authority under the Nebraska State Natural Gas
17 Regulation Act to grant an annual LCR increase in Aquila's overall revenue requirement
18 without a Section 66-1838 general rate filing.

1 **Q. Are there public policy reasons why the state statutory scheme should not be**
2 **amended to allow LCR filings?**

3 **A.** Yes, I am aware of a number of reasons why an LCR mechanism is contrary to good
4 public policy. In no particular order, I will list some of those reasons:

- 5 1. The Commission would be unable to make a reasoned determination that
6 Aquila's revenue requirement has increased without examining all costs and
7 all revenues. The LCR mechanism is a form of "piecemeal ratemaking", that
8 is, it ignores cost decreases and ignores revenue increases that could offset
9 cost increases. The LCR proposal increases the potential for over-recovery of
10 the revenue requirement.
- 11 2. Under the current ratemaking scheme, a utility must consider all costs, both
12 ups and downs, as well as revenue increases, when deciding whether to file
13 for a rate increase. Under the LCR, Aquila would simply increase selected
14 costs by the CPI-U, and rates would increase without regard to costs that may
15 have decreased or revenues that may have increased.
- 16 3. Rates should not be increased without rerunning the class cost of service study
17 to determine whether revenue requirements will continue to be fairly allocated
18 among the customer classes. The proposed LCR would not do this.
- 19 4. LCR mechanisms are not widely allowed in other jurisdictions.
- 20 5. The proposed LCR would increase the customer charge. This would shift
21 revenue collection within a class from larger customers to smaller customers.
22 This imposes the burden of the LCR rate increase upon those customers least

likely to afford it, and at a time when increasing gas commodity prices have already created financial hardships for those customers.

6. Moreover, increasing the customer charge shifts non-gas cost recovery away from usage to the fixed customer charge. This tends to run contrary to the goal of promoting energy efficiency through rate design.
7. The LCR does not strike a fair balance between the interests of ratepayers and the company. Under traditional ratemaking, there is no guarantee that the company will earn the allowed return. The utility must operate efficiently and prudently. The company has the duty to find ways to manage costs and increase revenues to offset rising costs. Under the LCR, the company will simply receive more revenue if the CPI-U increases, whether or not they discharge their duty to manage the costs. The automatic annual LCR increase upsets the traditional ratemaking paradigm in favor of the company, reallocating the risk and burden of rising costs from the company to the ratepayer.
8. We know of no other business that can simply raise prices without also working to achieve new efficiencies in its operations.
9. The burden to ratepayers under the LCR is not offset by commensurate benefit. The suggested benefit to ratepayers of avoiding rate cases does not offset the ratepayer burdens that accompany the LCR as described above.
10. The LCR rate increases will not be subject to the same rigorous scrutiny, investigation and cross examination that comprise the due process safeguards available to protect the ratepayer in a general rate case. Raising rates without

1 these due process safeguards is a taking of ratepayer funds without due
2 process.

3 11. Aquila has tools to manage increasing costs. Customer additions would
4 provide a source of increasing revenues. Prudent and diligent management
5 practices should be applied to manage costs between rate cases.

6 Conclusion

7 We certainly do not recommend implementation of an LCR mechanism. Our concern is
8 that adopting such a mechanism will lessen Aquila's resolve to manage costs. In the end,
9 if diligent management practices and increases in customer numbers do not offset cost
10 increases, Aquila has the statutory right to file a rate case.

1

2 **SECTION IX. ENERGY EFFICIENCY PROGRAMS**

3

4 **Q. Have you reviewed Aquila's proposals for a space and water heating rebates**
5 **program and a low income weatherization program?**

6 A. Yes, Aquila's witness, Matthew E. Daunis prefiled testimony in support of these Demand
7 Side Management (DSM) programs. I have reviewed his testimony and exhibits.

8 **Q. What is demand side management?**

9 A. Demand side management is an activity on the customer side (demand side) of the meter
10 designed to help meet the customers' energy needs.

11 **Q. How does the proposed Aquila space and water heating rebate program help to**
12 **meet customer energy needs?**

13 A. The space and water heating rebate program is designed to encourage the purchase of
14 more efficient space heating and water heating equipment. The more efficient equipment
15 will reduce usage, thereby helping to meet the customer's energy needs. The program
16 would provide rebates for the purchase of highly efficient space and water heating
17 equipment.

18 **Q. How is the cost of the program to be funded?**

19 A. Aquila has estimated the cost of the energy efficiency programs for the first three years of
20 the program and proposes to recover that cost through an energy efficiency surcharge of
21 \$0.0070/therm in the first year. Aquila proposes a balancing account to account for the
22 expenditures and surcharge revenues, with an annual report to be filed with the

Commission. Aquila proposes to adjust the surcharge in order to match the collections with the expenditures.

Q. Will the proposed space and water heating rebate program produce the desired results?

A. Mr. Daunis has included participation and program impact projections in his exhibits. He also projects cost-effectiveness and presents the results of his projections. Based upon his projections, the program benefits would appear to exceed the program costs.

Q. How does Aquila's proposed Low-income Weatherization Program benefit ratepayers?

A. The Nebraska Energy Office operates the federal weatherization program in Nebraska in cooperation with nine local agencies. Aquila proposes to provide funding to supplement the NEO program, allowing local agencies to serve additional households.

Q. What does the NEO program consist of?

A. The Nebraska program provides weatherization services and materials that include adding insulation, performing efficiency inspections, replacing windows, and installing weather stripping. Aquila funding would be allocated to the local agencies in proportion to the number of Aquila customers that each serves. The program would target Aquila gas customers that meet the federal income guidelines (less than 125% of the federal poverty level). The program would initially provide funding for weatherization of 70 homes, increasing to 100 homes per year in the third program year. Mr. Daunis has included in his exhibit program impact and cost effectiveness projections that would appear to show that the low income weatherization program should be cost effective.

1 **Q. Do you have a recommendation regarding Aquila’s proposed DSM programs?**

2 A. Yes. The rebate program is similar to rebate programs in other utilities that have been
3 used to encourage customer investments in energy efficient appliances. The low income
4 weatherization program is supplemental to the federal program. I am comfortable
5 suggesting that the Commission approve the proposed DSM programs with the
6 understanding that program participation and results will be reviewed from year to year
7 to test whether the programs are producing the expected benefits.

8

9 **Q. Does this conclude the public version of your pre-filed testimony?**

10 A. Yes it does.

1

2

SECTION X. CONFIDENTIAL SECTION

3

4

This section contains confidential information.

5

VERIFICATION

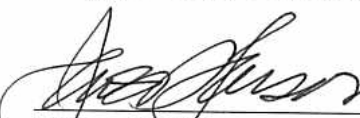
STATE OF MINNESOTA

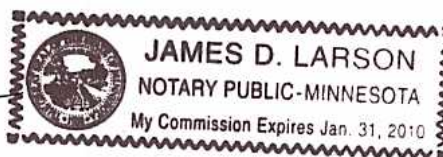
COUNTY OF HENNEPIN

William L. Glahn, being first duly sworn, states that he is the person referred to in the foregoing document entitled "Direct Testimony of William L. Glahn" before the Nebraska Public Service Commission of the State of Nebraska and the statements therein were prepared by him or under his supervision and direction and are true and correct to the best of his information and belief.


William L. Glahn

Subscribed and Sworn to
before the undersigned
this 15th day of March, 2007


Notary Public



STATE OF IOWA
DEPARTMENT OF COMMERCE
UTILITIES BOARD

IN RE: INQUIRY INTO THE EFFECT OF REDUCED USAGE ON RATE- REGULATED NATURAL GAS UTILITIES	DOCKET NO. NOI-06-1

ORDER ADDRESSING ISSUES AND CLOSING DOCKET

(Issued December 18, 2006)

On February 9, 2006, the Utilities Board (Board) initiated an inquiry into the effect of reduced natural gas usage resulting from increased energy efficiency and other factors over the next five years on the non-gas revenues of Iowa's rate-regulated natural gas utilities. The Board indicated that Iowa had joined with seven other states, Michigan, Minnesota, Missouri, Wisconsin, Ohio, Illinois, and Indiana, to form the Joint Natural Gas Price Reduction Initiative (JNGPRI) to support regional and individual state actions to create downward pressure on natural gas prices by reducing demand for natural gas by 5 percent over the next five years. The Board indicated that the states recognized that the high cost of natural gas created a financial hardship on many consumers and represented millions of dollars exported from these state economies.

The Board stated that the inquiry would investigate the potential effects of this initiative and other factors in reducing natural gas usage, the resulting effect on regulated non-gas utility revenues, and would consider whether traditional regulation

is flexible enough to address these effects or whether alternative mechanisms or approaches, such as a decoupling mechanism to reduce the influence of sales volumes on utility earnings, might be appropriate. The Board presented a set of initial questions in the February 9, 2006, order for participants to address.

Responses to the questions were filed by the Consumer Advocate Division of the Department of Justice (Consumer Advocate), Atmos Energy Corporation (Atmos), the Iowa Environmental Council (IEC), Interstate Power and Light Company (IPL), MidAmerican Energy Company (MidAmerican), Ag Processing Inc (AGP), the Iowa Industrial Energy Group (IIEG), and Aquila, Inc., d/b/a Aquila Networks (Aquila). As part of the inquiry, the Board contracted with the Regulatory Assistance Project (RAP) to conduct a workshop on May 10, 2006, addressing mechanisms considered in other jurisdictions to resolve these issues.

On July 11, 2006, the Board issued an order requesting responses to additional questions. The Board indicated that it had reviewed the initial comments, RAP presentation, and the discussions at the workshop and, based upon that information, the Board had questions about some of the mechanisms that were discussed. AGP, Consumer Advocate, MidAmerican, IPL, IIEG, and Aquila filed additional comments.

In considering whether a decoupling mechanism or similar system should be adopted in Iowa, the Board is faced with two important public policy concerns. First, there is the public policy goal of reducing usage of natural gas by individual customers with the result that overall usage in Iowa, and nationally, is reduced.

Second, there is the requirement under public utility regulation that a utility be given a reasonable opportunity to earn the return authorized by the regulatory agency. In many states these two public policy concerns have been found to be in conflict and various mechanisms to decouple sales of natural gas from a utility's revenues have been proposed to alleviate the tension between the two policies.

Based upon the information reviewed by the Board in this docket, the tension between energy efficiency and Iowa natural gas utilities' opportunity to earn their authorized rate of return does not appear to be a substantial problem in Iowa. Iowa utilities have been participating in energy efficiency plans since before 1990 without substantial adverse effects on earnings. In that year, Iowa established a statutory goal in Iowa Code § 473.3 to "more efficiently utilize energy resources . . . to decrease the state's dependence on energy resources from outside the state by reducing the amount of energy used." This goal was to be implemented through the development of programs that promote energy efficiency and energy conservation by all Iowans.

To meet this statutory goal, the Board developed rules and procedures for planning and implementing energy efficiency programs by Iowa public utilities and has approved several rounds of energy efficiency plans for rate-regulated utilities, most recently in 2003. The energy and peak capacity saved by investor-owned utility energy efficiency programs over the past 15 years have resulted in a cumulative reduction in natural gas usage through 2005 of about 7 million MCF, or about 6.6 percent of annual retail natural gas sales. By 2005, total customer retail cost savings

resulting from these cumulative changes in energy use amounted in 2005 to about \$80 million in natural gas costs. From this, the Board concludes that Iowa utilities have not been unable to engage in meaningful energy efficiency programs because of concern about their earnings.

The Board is committed to the continuation of the aggressive energy efficiency programs already in place and to the development of new plans to further increase savings to customers and reduced natural gas consumption from increased energy efficiency. This increase in energy efficiency programs by utilities and their customers may have an adverse effect on the ability of rate-regulated utilities to have a reasonable opportunity to earn their authorized rates of return, potentially creating a disincentive to utility participation in these programs.

Other jurisdictions that lack the energy efficiency mandate and history of Iowa have adopted decoupling mechanisms. The Board believes this may be appropriate in situations where reduced natural gas usage resulting from energy efficiency programs may adversely affect earnings. When this situation exists, utilities should be able to propose appropriate mechanisms to provide the utilities with a reasonable opportunity to earn their authorized rates of return in spite of reduced sales volumes. The information reviewed in this inquiry does not demonstrate that situation for Iowa utilities to date, but the Iowa utilities in this docket have nonetheless proposed several different alternatives solutions to declining customer usage, perhaps in anticipation of increased emphasis on energy efficiency programs. The suggested

changes included rate design proposals, incentive mechanisms, and automatic rate adjustments, among other things.

One reason that Iowa utilities may not be subject to the same pressures as utilities in other jurisdictions is that the Board allows recovery of the costs associated with approved energy efficiency plans through an automatic adjustment mechanism for natural gas utilities, the Energy Efficiency Cost Recovery (EECR). This pass through of energy efficiency plan costs alleviates some of the disincentive for utilities to promote greater energy efficiency by customers. The Board recognizes that the EECR may not be a complete answer, however, as it compensates utilities for expenditures but does not address the possible adverse effect reduced energy consumption might have on utility returns.

Information reviewed by the Board in this docket concerning Iowa natural gas utilities shows that Iowa rate-regulated utilities have experienced a reduction in average customer usage over the past ten years, as have utilities in other jurisdictions. The information does not indicate that reduced usage has substantially adversely affected utilities' net operating income. The Board examined annual reports from 1995 to 2005 for each of the four rate-regulated natural gas utilities showing the average residential usage by utility from 1995 to 2005, the net operating income of each utility over the same period, and the relationship between weather and total purchases of natural gas by utility over the same period. The data shows that average residential customer usage has declined and total purchases have declined while winter weather has generally been warmer than normal over the past

several years. 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.

However, it is unclear whether updated, more aggressive programs will change this situation. Each utility is likely to be affected differently, so each utility's situation should be considered separately. Separate consideration for each utility will allow the Board to determine whether any decline in net operating income is the result of a decline in customer usage due to increased energy efficiency or some other factor.

The Board believes decoupling mechanisms or rate design changes are appropriate when the circumstances support the need for such mechanisms. Some of the decoupling mechanisms that have been adopted in other jurisdictions are similar to the automatic adjustment mechanisms that are provided for pursuant to Iowa Code § 476.6(8). The Board has adopted these types of mechanisms to respond to costs that the utility management has little or no control over, that are volatile (i.e., subject to sudden and important changes in level), and that are an important factor in determining the total cost of service to customers. Under this statutory authority, the Board has adopted automatic adjustments for the purchase of natural gas, the purchased gas adjustment (PGA), and for fuel costs for electricity, the energy adjustment clause (EAC). The Board has also adopted an automatic adjustment mechanism, the EECR, pursuant to Iowa Code § 476.6(16), that

authorizes the recovery of the costs of implementing an energy efficiency plan approved by the Board.

At this time, the Board considers the standards established for the automatic adjustment mechanisms listed above to be the appropriate standards for considering whether there is a need for an automatic adjustment mechanism to compensate a utility for reduced customer usage because of increased energy efficiency. The decoupling mechanisms reviewed by the Board in this docket did not effectively identify the effect of increased energy efficiency by customers and often included other factors in the determination of when an adjustment would be made. The Board understands there may be a need by a utility to remove any disincentives that would limit promotion of increased energy efficiency, however, decoupling mechanisms that adjust for other factors may go beyond what the Board considers to be reasonable.

A review of the decoupling mechanisms suggested by the participants shows there was not a general consensus supporting use of decoupling mechanisms or a single type of mechanism. Since there was a lack of consensus, the Board will not attempt to establish a single, specific automatic adjustment mechanism that would be applicable to all of the rate-regulated utilities. Instead, the Board will encourage each utility to review its circumstances and determine if increased energy efficiency and reduced customer usage have caused, or are likely to cause, a decline in net operating income. If a relationship is shown, the utility should develop a proposal that may include an automatic adjustment mechanism, rate design change, or other solution that it considers reasonable to address the situation and should make the

appropriate filing with the Board for consideration in an appropriate proceeding. Since each rate-regulated utility will make a separate determination of whether it should make a filing and those filings will be considered in separate dockets, no further action is required in this docket. Docket No. NOI-06-1 will therefore be closed.

IT IS THEREFORE ORDERED:

Docket No. NOI-06-1 is closed.

UTILITIES BOARD

/s/ John R. Norris

/s/ Diane Munns

ATTEST:

/s/ Judi K. Cooper
Executive Secretary

/s/ Curtis W. Stamp

Dated at Des Moines, Iowa, this 18th day of December, 2006.

Decoupling

Rate Tracking for Declining Sales
A Piecemeal Approach

Mike Brosch – Utilitech, Inc.



Traditional Test Year Regulation

- Test Year Revenue Requirement
 - Synchronized measurement of all elements
 - Rate Base (Average or Year End)
 - Cost of Capital
 - Sales Volumes / Revenues
 - Operating Expenses
 - Matching is Key Concept / often Challenged
 - Utility Interest in “Reaching” for negative trends
 - Consumer Interest in “Reaching” for positives
 - Balanced Response is to Cut off at Common Date



Benefits of Test Year Approach

- Imposes Structure and Balance
 - Parties are forced to acknowledge both favorable and unfavorable changes at date X – **not piecemeal**
 - Financial need must be proven, nothing is automatic
 - Parties have formal process for discovery, analysis and issue development
 - Resources are focused upon analysis
 - Regulatory Lag Incentive
- Captures all margin changes in Test Year



Is Regulatory Lag “Bad”?

- Traditional Regulation is Often Criticized as being “cost plus” in nature, rewarding the inefficient.
- However, regulatory lag replaces some of the lost efficiency incentive, because, between rate case test years, revenue and cost changes go to shareholders
- Rate tracking tariffs selectively eliminate regulatory lag – for isolated types of changes between test years
- Are sales incentives desirable for energy utilities?



Tracking Tariffs in General

- What They Do
 - Change Rates on Single Issue Basis
 - Reduce Regulatory Lag
 - Change Incentives
 - Change Financial Results
 - Increase Regulatory Complexity
- Impact on Consumers
 - Destroys Matching
 - Eliminates Regulatory Lag Efficiency Incentive
 - Shifts Risks/Costs
 - Increases Prices
 - Increases Utility ROR
 - Consumes Regulatory Oversight Resources



Decoupling in Particular

- Price Adjustment Tariff – margin revenues (revenues less fuel cost recovery) are tracked, with rate adjustments to ensure recovery of amounts approved in rate case
- Typically advocated on a “per customer” basis, allowing shareholders to retain margin growth from adding new customers
- Incorporates weather normalization
- Scope >residential & small commercial

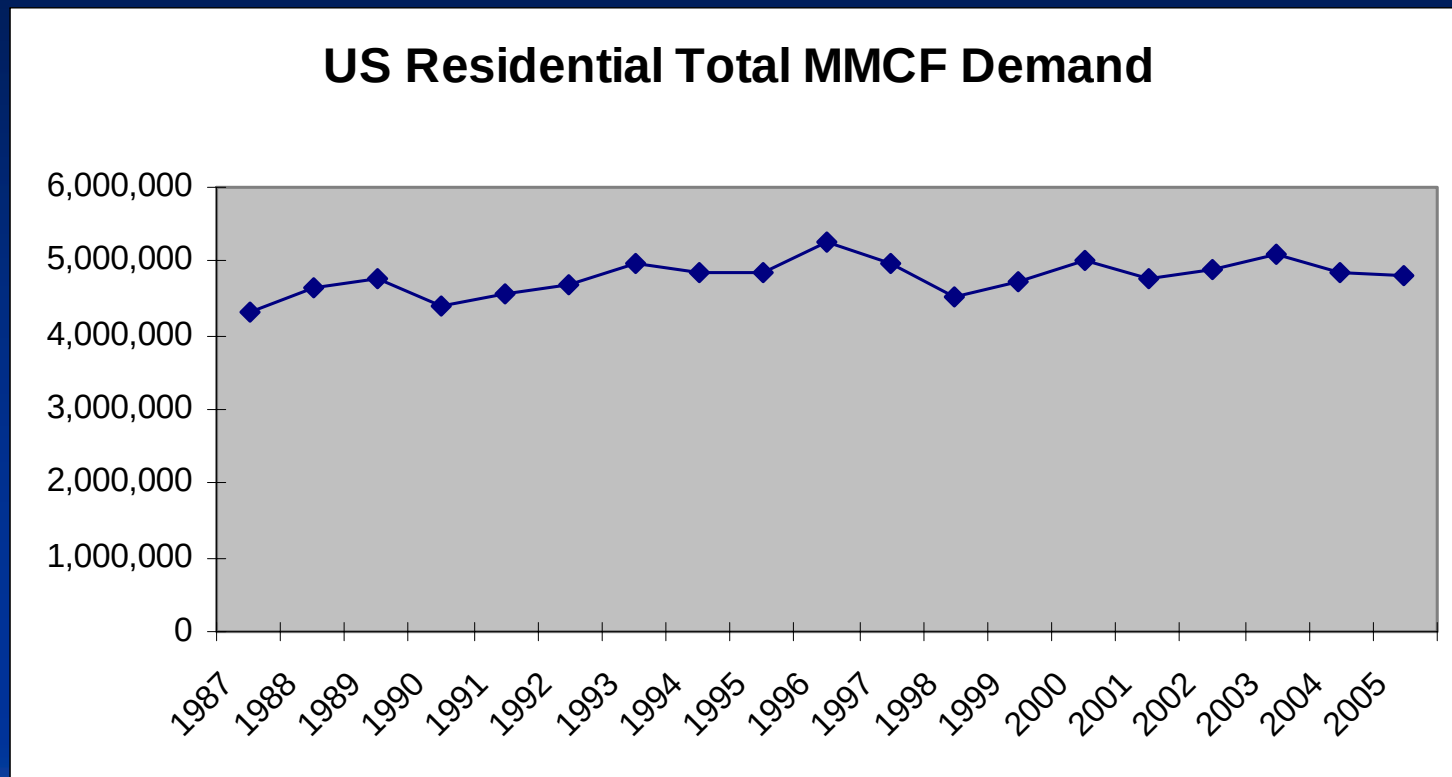


Only “Partial” Decoupling Wanted

- Utility Sales Revenues are Price times Quantity ($P \times Q$)
- Sales Quantities “Q” are product of Number of Customers times Usage Per Customer
- Decoupling Advocates want to track changes in usage “per customer”, retaining customer growth new margins for shareholders
- “Full” decoupling would adjust rates to maintain the dollars of margin revenue authorized



Stable Overall Usage Trends

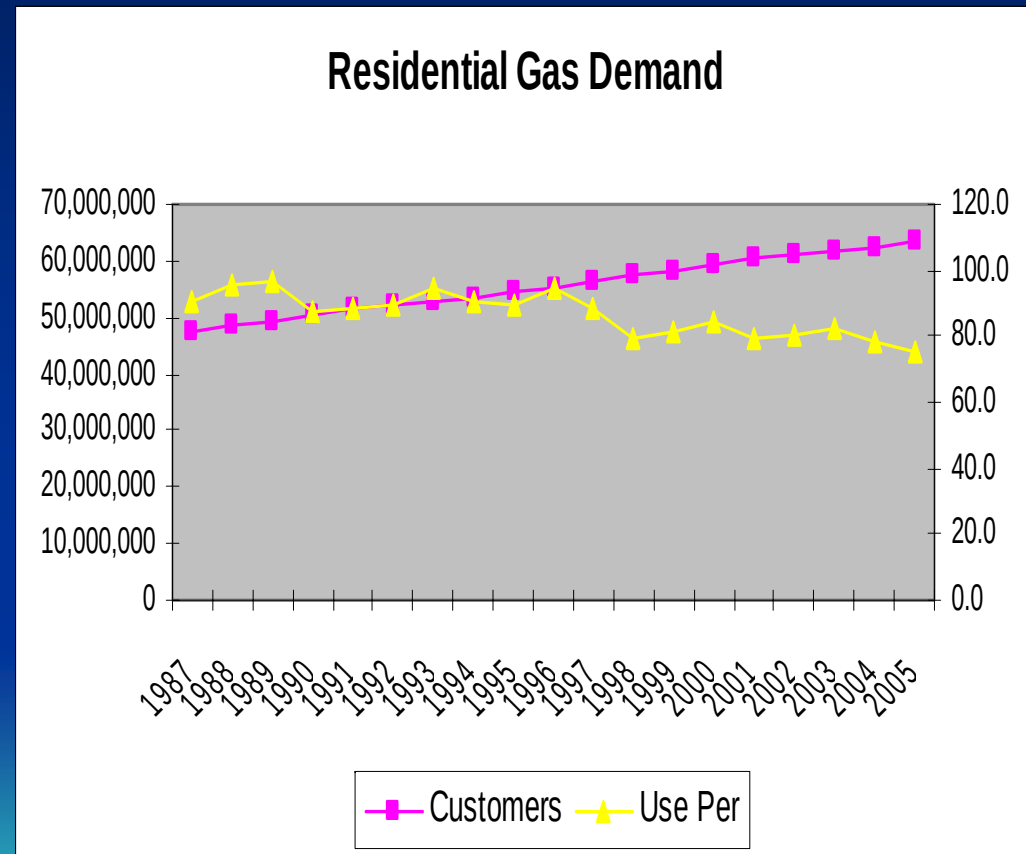


Total US deliveries of natural gas to residential customers are relatively constant, with customer growth offsetting declining usage per customer.

EIA Natural Gas Navigator: <http://tonto.eia.doe.gov/dnav/ng/hist/n3010us2a.htm>

Declining Use Per Customer

- LDC Residential usage per customer has long been declining
- Forecast is for trend to continue – high price impact
- But: Customer count trends are favorable overall
- Which trend should be tracked?
- The industry answer is “partial” decoupling



Decoupling Impacts

- Track usage per customer margin changes (\$/cust)
- Said to remove the “Incentive to Promote” Usage (or the Disincentive to Conserve)
- Improves financial results
- Adds Complexity
- Stabilizes margins for weather fluctuations – locks in margin per customer
- Consumer pay more if they successfully conserve
- Utility can still grow or maintain margins by adding customers
- Additional margins may not be needed to earn adequately
- More filings and “audits”?
- Are margins trending down? faster than costs?



Responsive Points

- Disclose the “real” margin trends
- Address the Disincentive Argument
- Apply generally accepted regulatory theories (matching) and tracking criteria
- Evaluate financial “need” for piecemeal relief
- Illustrate customer impacts (risk/cost shifting)
- Identify regulatory burdens
- Demonstrate how conservation can happen without decoupling



Decoupling Analysis Areas

- Evaluate Financial Need
 - Historical ROR Achieved?
 - Rate Case Frequency?
 - Historical customer, sales, use/per trends?
 - Projected sales, customer use/per?
 - Offsetting productivity and automation efforts
 - Backcasts/projections
- Apply General Criteria
 - How large and volatile are \$ at issue?
 - Is conservation (not weather) causing observed margin/earnings volatility?
 - Does utility have any control?
 - Is customer growth offsetting declining usage trends?
 - What are internal and PUC costs to administer proposed mechanism?



Actual Margin Trends?

- Typical LDC margins fluctuate with modest trends
 - Get weather normalized actual historical data to see how customer growth and conservation trends compare
 - Request or build back-cast of history with decoupling.
- Examine projected margins, with/without decoupling



The Disincentive Argument

- Traditional Regulation Provides an Incentive to “grow” sales, which is contrary to the broader public interest in conservation
- Decoupling is said to be needed to remove this disincentive
- The utility argues it should not be “punished” when customers conserve
- Full utility support for conservation is therefore said to be assured only with decoupling



Intuitive, But Wrong



- Most conservation is structural and beyond utility control
 - Federal appliance efficiency standards NAECA
 - Building efficiency standards/code
 - High gas price Dial-back (elasticity)
 - Customer funded conservation investment
- Gas is often not competitive unless efficient use is promoted
- Decoupling is overly broad – targeted incentives, if needed, can be better at rewarding effective utility-funded conservation programs
- 3rd Party Admin Blunts this Argument

Conservation Savings Dilution

- Decoupling quickly raises utility prices when customers conserve – reducing savings to consumers
- Customers get commodity savings from conservation, but no delivery charge savings
- Conservation program costs are borne by customers – but decoupling dilutes benefits



Decoupling is Extraordinary Relief

- Test Year Matching is Preferred – exceptions should be approved only if extraordinary conditions exist
- Apply generalized criteria that are beyond refute
- Note that few tracking tariffs are broadly accepted – best example may be PGA
- One-sided trackers will spread if precedent is established



General Criteria for Tracking

- Regulators have considered several generalized criteria in review of proposed rate riders/trackers:
 - Is the cost/revenue element individually large and volatile?
 - Will the financial performance of the utility be harmed if tracking is denied?
 - Is the cost/revenue change outside management control?
 - Is the complexity and administrative cost of the tracking tariff justified?
 - Is matching principal violated, because offsets are ignored?



Decoupling Under These Tests

- Conservation trends do not produce large swings in volumes or margins - these are gradual long-term effects as homes and appliances are replaced and conservation investments are made
- LDCs have experienced financial stability without decoupling tariffs, needing only periodic rate cases to rebalance costs/rates
- Customer usage is largely outside the control of management (forget that disincentive argument)
- Administrative cost and complexity are avoidable
- Matching is violated, because customer growth is ignored



Other Arguments Pro/Con

- Utilities are entitled to collect approved margin \$
- Declining usage is beyond management control
- Margin income should be stabilized
- Improved ability to earn authorized ROR is needed
- Revenue growth is needed to meet rising costs
- Alignment of utility interests with conservation ethic
- Utility can “afford” to fund conservation only with relief
- Opportunity to earn ROR is not guarantee of margin dollars
- What about those claimed disincentives?
- Margin instability may be met with WNA clause
- Conservation trends are long-term, yet rate cases are infrequent
- Usually unproven, but if true a rate case can be filed by the utility
- If disincentive is feared, use targeted incentives or 3rd party admin



Stabilization Alternative - WNA

- Margin Fluctuation due to Weather Does Not Require Decoupling
- WNA Clause Adjusts Prices for Weather Alone
 - Symmetrical – Earnings Neutral
 - Can mitigate bill impacts
 - Administrative Complexity



Stabilization Alternative - SFV

- Delivery margin stabilization has been pursued for years through increased customer or move to SFV rates
- Unpopular customer impacts:
 - High low volume (summer) bills
 - Dilution of conservation incentive/reward
 - Seasonal disconnects – reconnect fees
- Level pay plans are optional & effective



Conservation Alternatives

- Third Party Administration of Utility Funded Conservation
- Performance Reviews with Rate Case Implications
- Targeted Incentives for Conservation Performance
 - Targeted Incentives for Nega-therms
 - Lost Margins Measurement / Replacement



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Regulatory Issues for Consumer Advocates in Rate Design, Incentives & Energy Efficiency

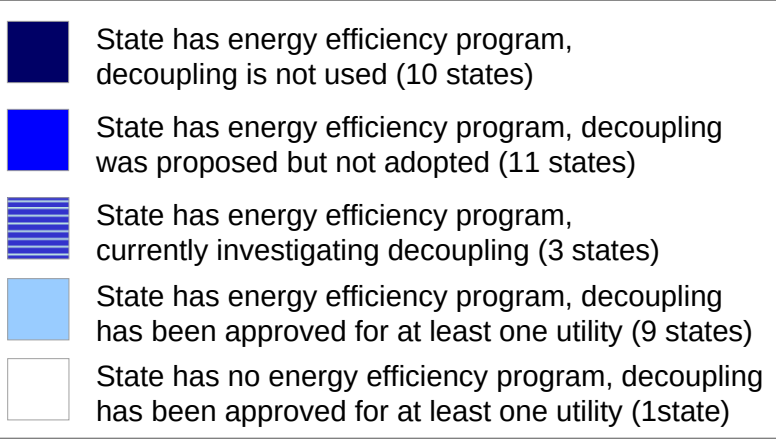


David E. Dismukes, Ph.D.
Professor & Associate Executive Director
Center for Energy Studies
Louisiana State University

**National Association of State Utility Consumer Advocates
(NASUCA)
Mid-Year Meeting
June 11, 2007**

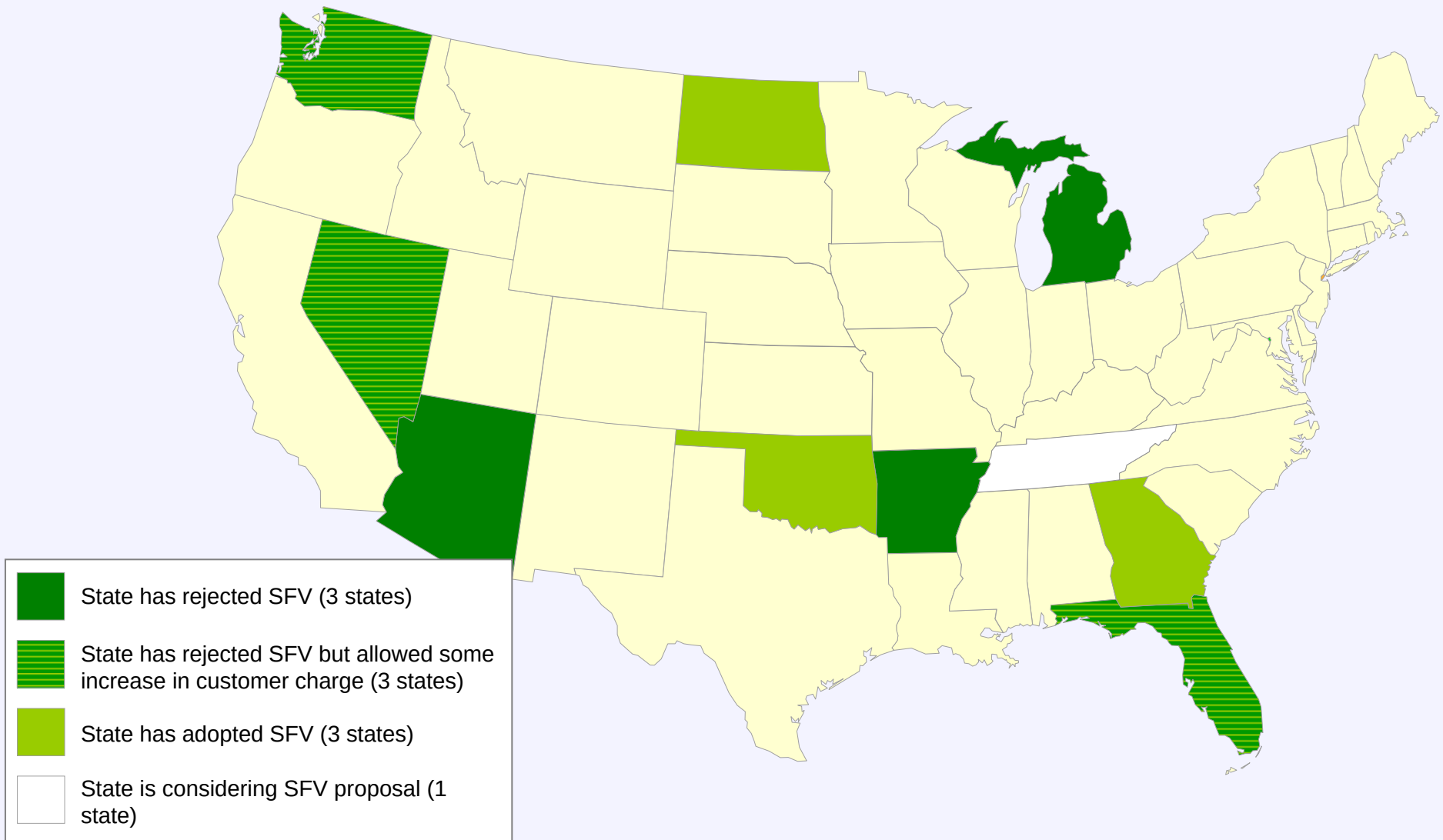
- Aligns utility incentives with energy efficiency.
- Assists utility in earning its authorized rate of return that is challenged by the decreasing use per customer problem (gas).
- Easier for customers to understand and reduces bill volatility.
- Reduces regulatory costs and the need for frequent rate cases.

- Straight-Fixed Variable Rate Design: eliminates all variable distribution charges and DNG costs are recovered through a fixed delivery services charge or an increase in the fixed customer charge alone (gas LDCs).
- Sales-Revenue Decoupling: separates revenue recovery from sales (sets annual revenues to a “per-customer” target.) Can be done on a full or partial basis.
- Sales-Margin Decoupling: separates margin recovery from sales (sets margin per customer target). Can also be done on a full or partial basis.



Note: In Connecticut, the electric utilities do not have decoupling, but two natural gas LDCs have a partial decoupling mechanism in connection with their energy efficiency programs for low-income customers (a conservation adjustment mechanism). Washington has utilities with decoupling, but rejected the most recent utility proposal (January 2007). In Michigan, revenue decoupling was proposed by the Michigan Staff but opposed by the Michigan AG. The MPSC approved a stipulation that excluded revenue decoupling. In Kansas, revenue decoupling was proposed by Aquila. The parties involved agreed to a stipulation that excluded revenue decoupling while the Commission investigates it further in a general docket.

States that have Considered SFV



Note: In Michigan, SFV was proposed by SEMCO Energy but opposed by the Michigan AG. The MPSC approved a stipulation that excluded SFV .

Common Reasons for Rejecting Revenue Neutrality

- Represents a significant departure from traditional regulation.
- Shifts sales risks from utilities to customers.
- The impact of changes in use per customer for the gas industry are overstated and address the wrong causes on changes in margins. Power industry faces an entirely different set of usage trends.
- At best, the incentive issue is not resolved and never can be with revenue decoupling.
- Current proposals, offered in conjunction with other “regulatory remedies” diminishes the simplicity argument and raises questions about the purpose of proposal.
- Proportionality issue – changing the rate design for all customers based upon programs for which an exceptionally small percentage of the customers will participate.
- Is actually contrary to “sound economic principles” and well-grounded regulatory policies.

Economy

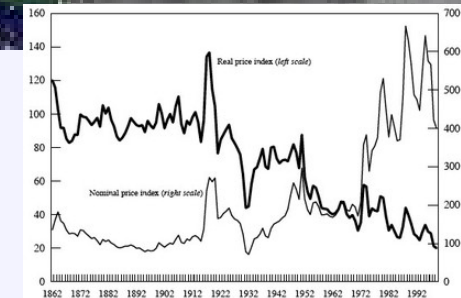


Weather

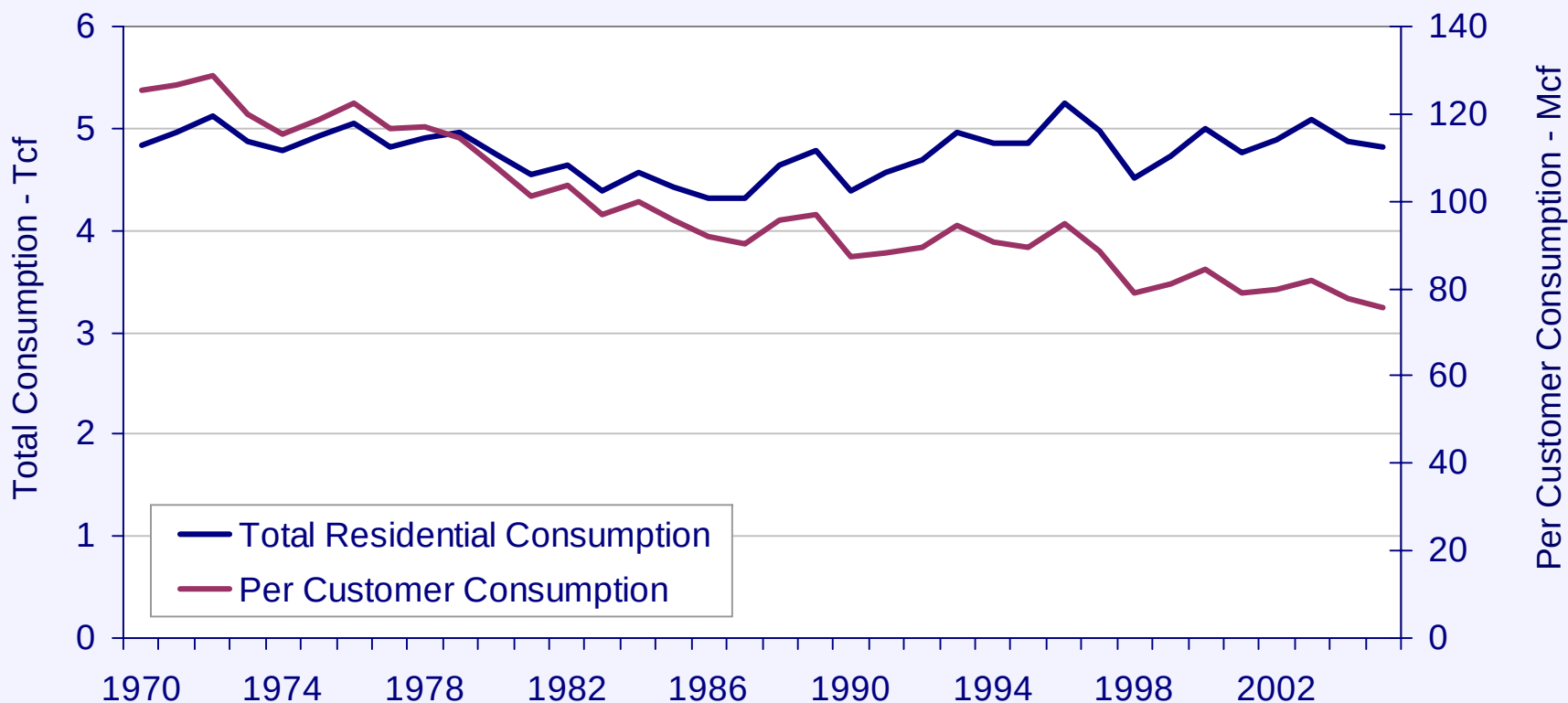


Commodity Prices

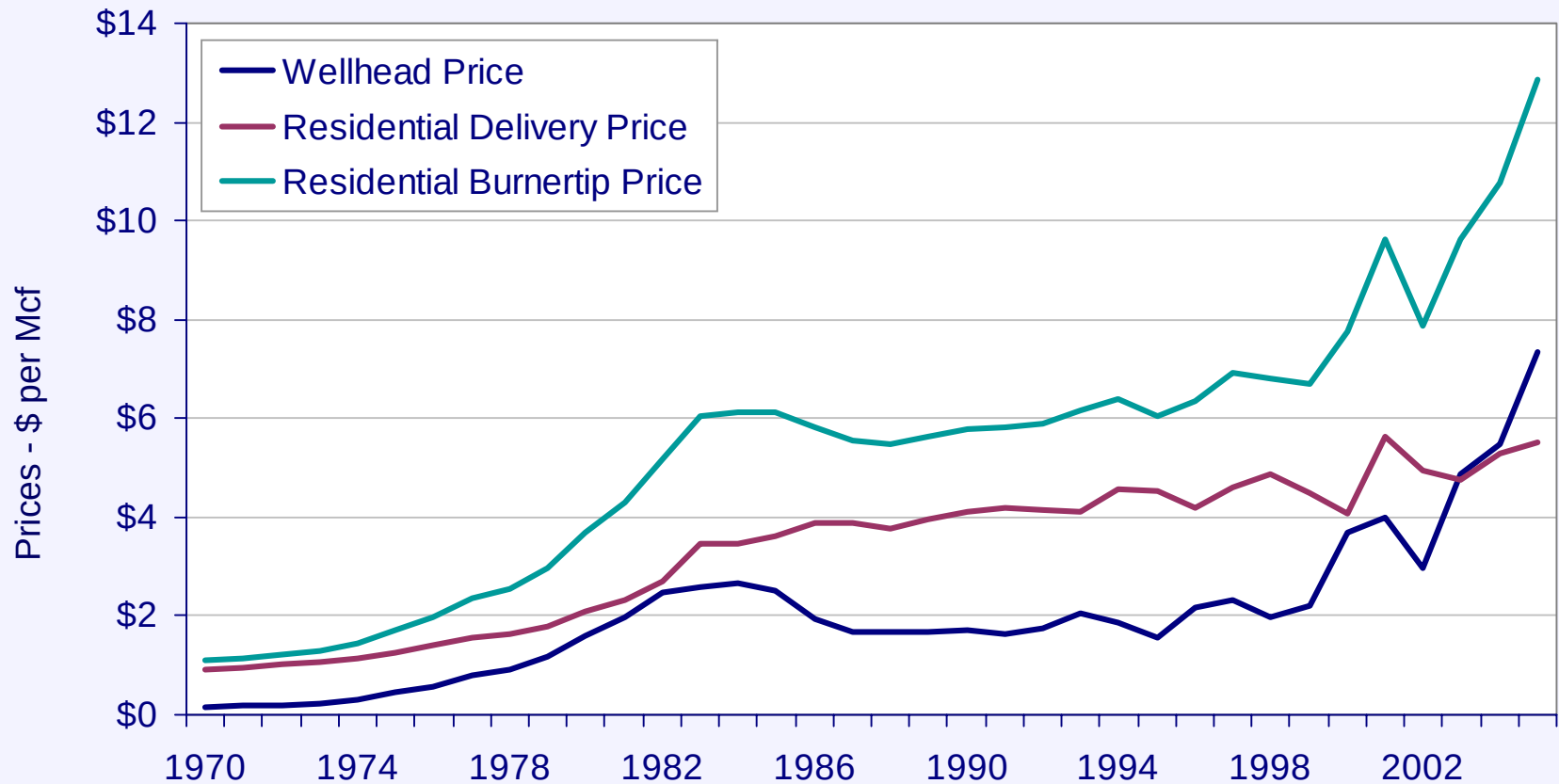
Other Unanticipated Factors



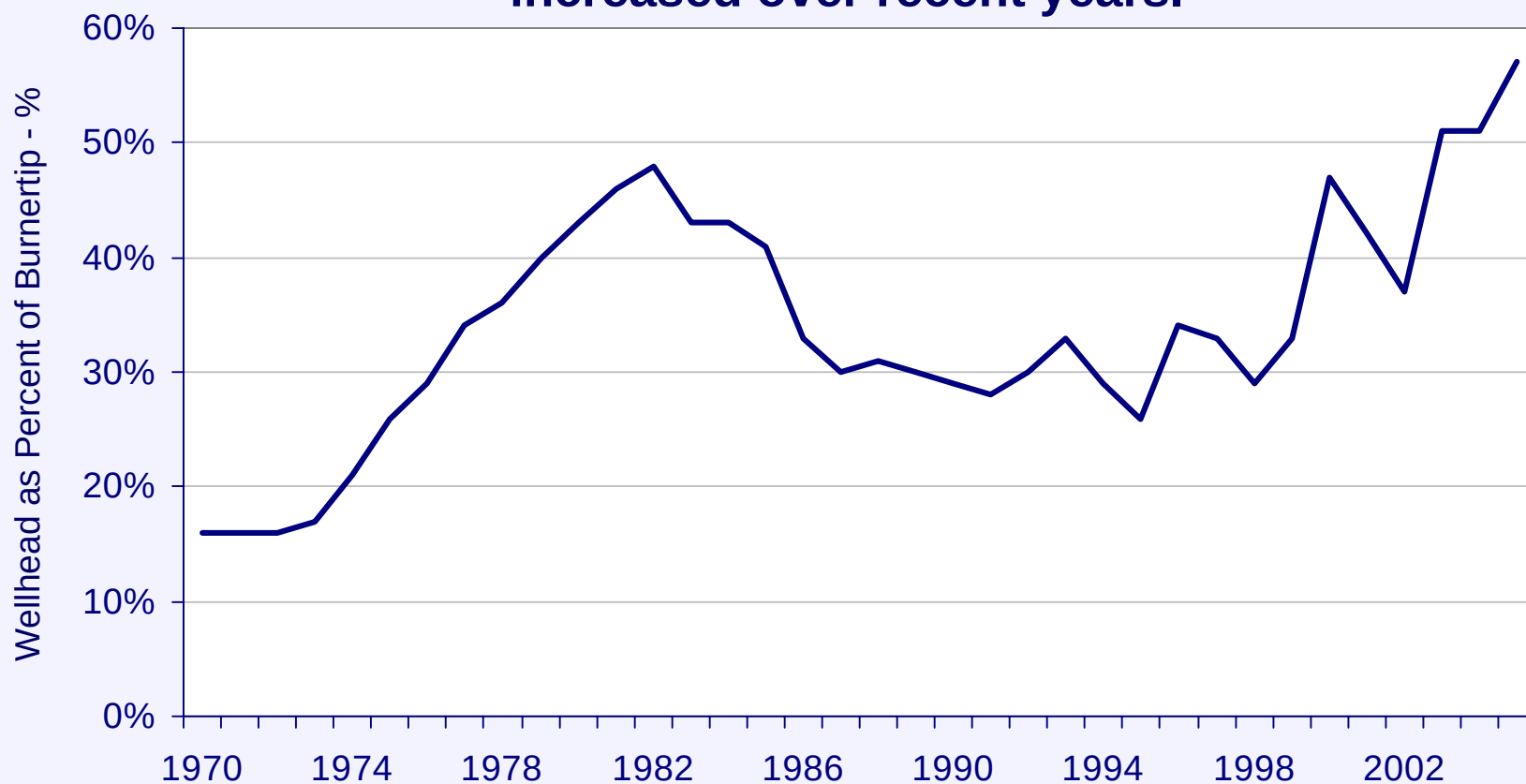
While overall use per customer is decreasing, overall residential natural gas usage is flat to increasing.



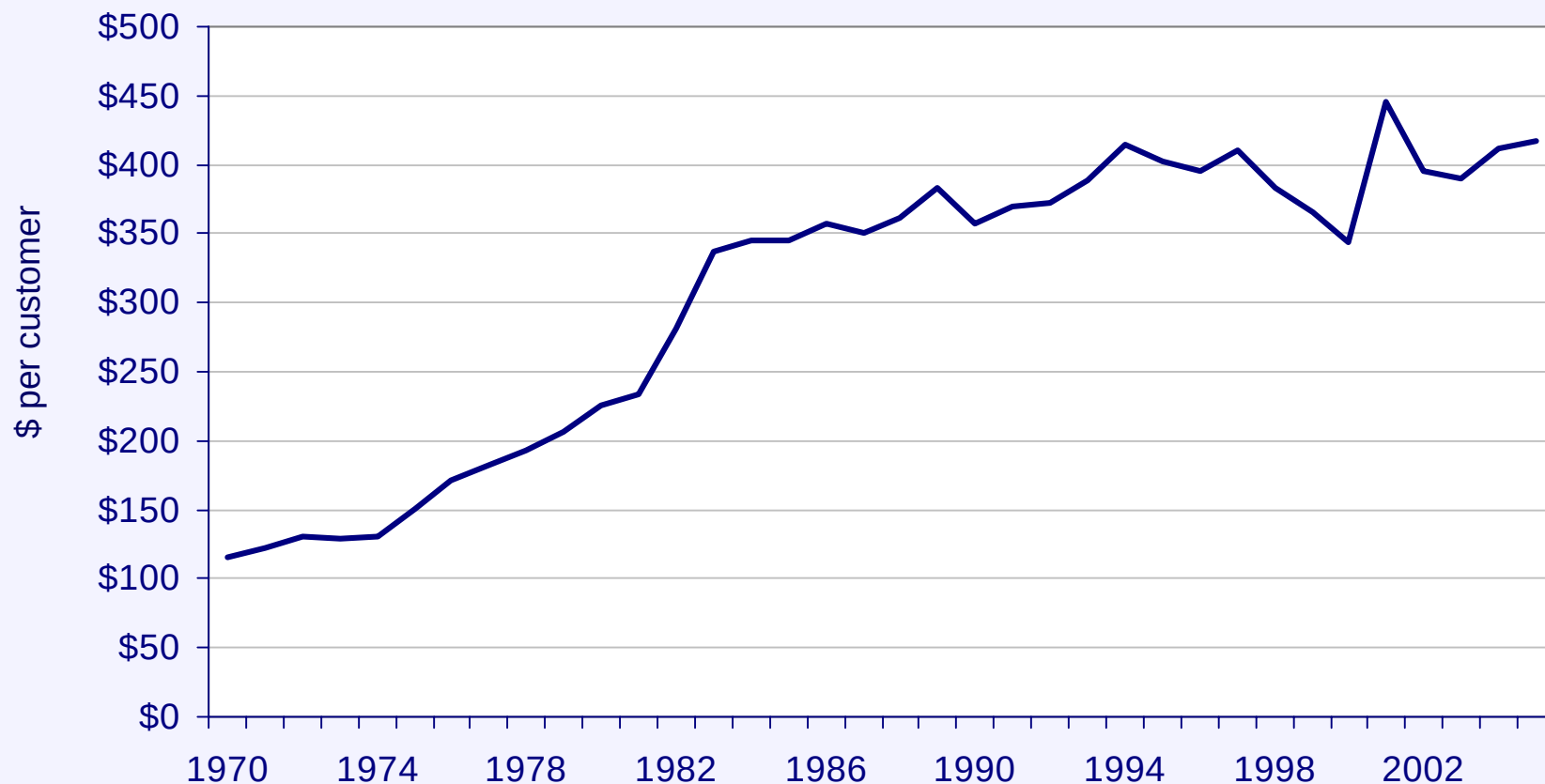
Retail prices have increased significantly since 2000-2001.



The commodity share of overall natural gas rate has increased over recent years.



Yet despite high prices, and decreases in use per customer, overall DNG revenues per customer are at close to historic highs.



Summary Financial Impact of Changes in Use and Customers, “Wild West Utility” (2001-2005)

Wild West LDC is facing significant growth challenges – ROE impacts of decreases in use per customer pale in comparison to change in rate base and new customer capital expenses.

	2001	2002	2003	2004	2005	2006
<u>Return on Equity</u>						
Allowed ROE	11.00%	11.00%	11.20%	11.20%	11.20%	11.20%
ROE Impact of Change in Use per Customer	0.00%	-0.60%	1.99%	-0.41%	-0.87%	-0.41%
ROE Impact Change in Customers	0.00%	1.04%	1.66%	1.17%	1.51%	1.51%
ROE Impact Change in Expenses Rate Base and Capital Elements	-0.54%	-2.38%	-3.76%	-1.92%	-1.16%	-2.08%
Actual Achieved ROE	10.46%	9.06%	11.09%	10.05%	10.68%	10.22%

Is decoupling a solution to the “use per customer problem” or an “end-run” on a rate case?

Significant change in rate design for a very small change in overall sales and very limited number of customers.

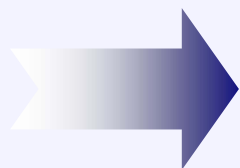
	Program Spending (million \$)	Percent of Retail Revenues (%)	Gas Savings (Mcf/year)	Percent of Gas Sales Saved (%)	Volume saved per million \$ (Mcf/year)	Benefit- Cost Ratio
Aquila	\$ 2.10	1.4%	146,000	0.5%	69,000	-
Centerpoint	\$ 5.60	0.5%	720,000	0.5%	128,600	2.60
Keyspan	\$ 12.00	1.0%	490,000	0.4%	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

Generally, less than one-half of one percent.

Incremental Impact of DSM Implementation on Shareholders, Wild West Utility

	Change in Revenue			Income Impact			Shareholders Equity	Impact on ROE
	Use per Customer	DSM	New Customers	Use per Customer	DSM	New Customers		
2007	\$(1,971,361)	\$ (288,537)	\$ 7,052,203	\$(1,221,185)	\$ (178,738)	\$ 4,368,579	\$ 313,071,056	0.95%
2008	\$(2,905,519)	\$ (608,826)	\$ 6,391,367	\$(1,799,862)	\$ (377,145)	\$ 3,959,215	\$ 339,501,229	0.52%
2009	\$(4,485,340)	\$ (943,652)	\$ 6,213,829	\$(2,778,502)	\$ (584,557)	\$ 3,849,237	\$ 363,965,179	0.13%
Total	\$(9,362,220)	\$(1,841,015)	\$ 19,657,399	\$(5,799,549)	\$(1,140,440)	\$ 12,177,031	Net Impact:	1.61%
								\$ 5,237,041.80

**Exaggerated
Example**

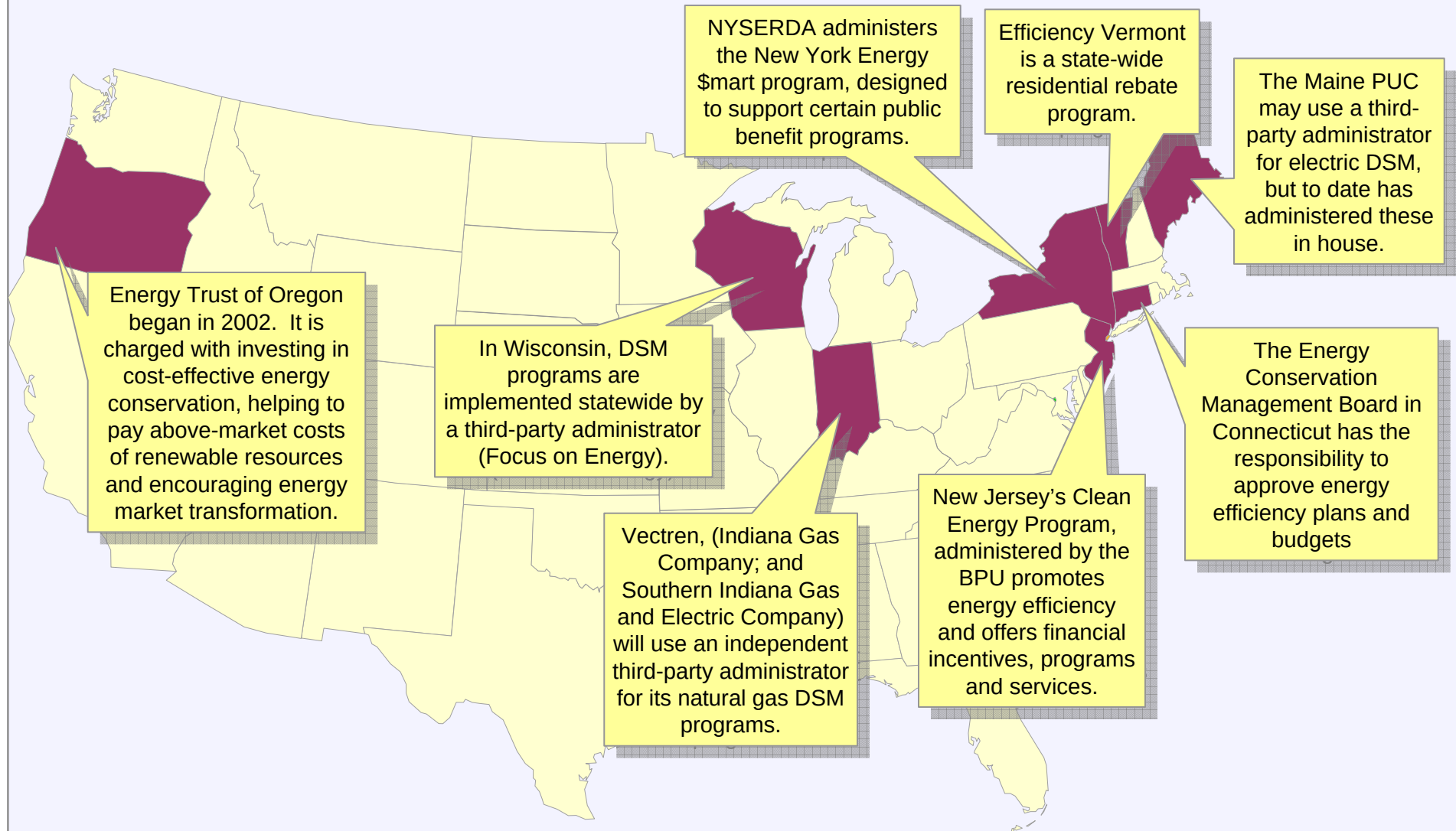


- Reduced revenues/income reduces overall taxes and needs to be considered.
- A one percent per year (3 percent cumulative) reduction is beyond current experience.
- The additional income created by customer growth from the test year is completely ignored (and its corresponding income effects).
- Net impact for a growing LDC is moderate – the net income impact is still positive, not negative.

- Reduces customers' ability to have full control of their energy savings. Reduces, in part, incentive to conserve particularly with SFV.
- If successful in reducing sales incentive, then also reduces incentive to measure sales losses and savings. You have "decoupled" DSM performance to any form of measurement.
- If successful in reducing sales incentive, then reduces incentive to promote efficient natural gas use and economic development.
- Revenues more difficult to estimate than costs, creating revenue certainty reduces incentive to push cost efficiency.

*George A. Schreiber, Jr., SEMCO Company President and Chief Executive Officer, said, "I am very pleased with the Company's results for 2006. We achieved these results, despite warmer-than-normal temperatures and continued customer conservation, which, when combined, adversely impacted 2006 earnings by an estimated \$3.5 million." Schreiber added, **"One way we overcame the impact of the weather and customer conservation was to keep spending under control."***

States with Third-Party Administrators



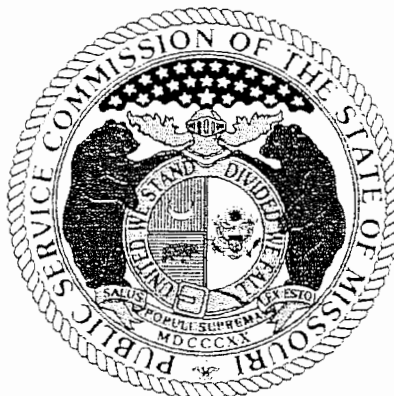
- **Projected test years:** forecasts could account for anticipated energy efficiency savings.
- **Cost-effectiveness tests:** screening on RIM-passing measures only.
- **Lost Revenues (*ex post*):** periodic filings on proven, *ex post* lost revenues/sales.
- **Rate design (inclining blocks):** higher rates in upper blocks.
- **Repression adjustments:** usage adjustment to correct of DSM-related reductions in usage.
- **Direct Incentives:** performance-based incentives for programs.
- **Risk Management:** if volatility is an issue, then manage it.
- **More frequent rate cases:** traditional approach at correcting rates that get out of balance.

Questions, Comments, & Discussion

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**BEFORE THE PUBLIC SERVICE COMMISSION
OF THE STATE OF MISSOURI**



In the Matter of Atmos Energy Corporation's Tariff	)	
Revision designed to Consolidate Rates and	)	<u>Case No. GR-2006-0387</u>
Implement a General Rate Increase for Natural Gas	)	<u>Tariff No. YG-2006-0T62</u>
Service in the Missouri Service Area of Atmos.	)	

REPORT AND ORDER

Issue Date: February 22, 2007

Effective Date: March 4, 2007

BEFORE THE PUBLIC SERVICE COMMISSION

OF THE STATE OF MISSOURI

In the Matter of Atmos Energy Corporation's Tariff)
 Revision designed to Consolidate Rates and) **Case No. GR-2006-0387**
 Implement a General Rate Increase for Natural Gas) **Tariff No. YG-2006-0T62**
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Marc D. Poston, Senior Public Counsel, Office of the Public Counsel, Post Office Box 2230, Jefferson City, Missouri 65102, for the Office of the Public Counsel and the public.

Kevin A. Thompson, General Counsel, **Lera L. Shemwell**, Senior Counsel, and **Robert S. Berlin**, Associate General Counsel, Missouri Public Service Commission, Post Office Box 360, Jefferson City, Missouri 65102, for the Staff of the Missouri Public Service Commission.

REGULATORY LAW JUDGE: Nancy Dippell, Deputy Chief Regulatory Law Judge .

REPORT AND ORDER

Syllabus: This order rejects the general rate increase originally requested by Atmos Energy Corporation. The order also authorizes Atmos to file new tariff sheets in compliance with this order. If Atmos files new tariff sheets with the new fixed monthly charge rate design, it shall also implement an efficiency and conservation program as set out herein. Otherwise, the Commission finds that Atmos shall maintain its current rate structure with no additional revenue required.

Findings of Fact

The Missouri Public Service Commission, having considered all of the competent and substantial evidence upon the whole record, makes the following findings of fact. The positions and arguments of all of the parties have been considered by the Commission in making this decision. Failure to specifically address a piece of evidence, position or argument of any party does not indicate that the Commission has failed to consider relevant evidence, but indicates rather that the omitted material was not dispositive of this decision.

Procedural History

On April 7, 2006, Atmos filed revised tariff sheets which set forth revised rate schedules and certain revised charges for all of Atmos' service territories in the state of Missouri, designed to produce an increase of approximately \$3.4 million in new revenues for Atmos. The new rate schedules would increase revenues to provide an

overall rate of return on rate base of 8.59 percent on the test year rate base of \$56.0 million.¹

Atmos is the largest pure natural gas distribution company in the United States, with corporate offices located in Dallas, Texas. Atmos is comprised of six gas utility operating divisions, and its Mid-States Division (located in Franklin, Tennessee) provides natural gas distribution service in Missouri, Tennessee, Virginia, Georgia, Kentucky, Illinois and Iowa. Regional and state offices for the Missouri operations are located in Hannibal, Jackson and Sikeston. Atmos serves approximately 60,000 customers in Missouri, and the customer base includes residential, commercial and industrial customers. Employing a Missouri-based work force of approximately 75 employees, Atmos utility system includes over 2,150 miles of transmission and distribution lines.²

Atmos consists of six base rate areas located in the northeast, southeast and west-central areas of Missouri, and are the result of the following acquisitions: Greeley Gas Company purchased in 1993; United Cities Gas Company purchased in 1997; and Associated Natural Gas Company purchased in 2000.³

Atmos had not filed for a rate case since acquiring these Missouri service areas, so the rates for each district were set when the preceding utility had its last rate case. United Cities filed its last rate request in Missouri in 1994, and rates were

¹ Ex. 1, pp. 5-6, 10-11.

² Ex. 1, pp. 4-5, 10.

³ Ex. 1, p. 3; Ex. 110, pp. 1-2.

approved and implemented in 1995. The last rate increase affecting the utility properties Atmos acquired from ANG was filed, approved and implemented in 1997.⁴

A "Joint Issues List, List of Witnesses and Order of Cross-Examination" was filed by the Staff of the Commission on behalf of the parties, on November 14, 2006. As set forth in the "Joint List of Issues," the parties identified the following issues as being resolved:

1. Billing determinants
2. Research and development order
3. Noranda Fall issues)
4. Class share of revenue by district
5. Uncollectibles in the MGA
6. Customer Service issues
7. Class Cost of Service

In addition, local public hearings, a rate design technical conference, a settlement conference and evidentiary hearings were held in this matter. The parties each submitted prehearing and post hearing briefs, or a statement declining to do so. The post hearing briefs were submitted on January 19, 2007.

On December 12, 2006, the second part of Exhibit 144 was filed by Staff. No objection to the exhibit was received, and it is hereby admitted into evidence.

The Partial Stipulation and Agreement

In addition to the issues identified as being resolved in the Joint Issues List of November 14, 2006, Atmos, Staff and the Office of the Public Counsel submitted their Partial Non-Uniform Stipulation and Agreement to the Commission for approval on November 29, 2006. The Agreement sets forth additional issues settled among those parties. Staff filed its memorandum in support of the Agreement on December 12,

⁴ Ex. 1, p. 5; Ex. 110, p. 3.

2006. No party opposed the Agreement. Therefore, as permitted by Commission Rule 4 CSR 240-2.115, the Commission shall treat the Agreement, attached to this Report and Order as Attachment A, as if it were unanimous. The Commission finds the Agreement just and reasonable and, therefore, approves it. In its discussion of the issues as set forth by the parties, the Commission will identify and address those specific components that have been resolved pursuant to the Agreement.

The Issues

1. What is the appropriate revenue requirement?
 - a. What is the appropriate level of expense?
 - b. What is the appropriate rate of return / return on equity?
 - c. What is the appropriate level of revenue excess / deficiency?

Ratemaking involves two successive processes. First is the determination of the revenue requirement; the amount of revenue the utility must receive to pay the costs of producing utility service while yielding a reasonable rate of return to the investors.⁵ The second process is rate design, the construction of tariffs that will collect the necessary revenue requirement from the ratepayers.

Atmrs' gross annualized revenue of \$16,507,737 was stipulated to in the Mutual Non-Consensus Stipulation and Agreement. Atmrs' revised tariff sheets as originally proposed would have increased revenues to provide an overall rate of return on rate base of 8.59 percent on the test year rate base of \$56.0 million. The original proposal also contained a weather mitigation adjustment in the rates. Atmrs' requested return on common equity (ROE) in this case was 12 percent.⁶

⁵ *St. ex rel. Capital City Water Co. v. Missouri Pub. Serv. Comm'n*, 850 S.W.2d 903, 916 n 1 (Mo. App., W.D. 1993).

⁶ Ex. 14, pp. 29-31.

Staff initially calculated a \$1.2 million revenue excess. Staff is not seeking a revenue reduction or filing an excess earnings complaint. After evaluating the positions of the parties (a difference of \$4.4 million), Staff believed there was a significant chance that it would not prevail in its entire revenue reduction. Furthermore, if Staff failed to prevail on all its issues, Staff believed that Atmos might end up with a revenue increase.⁷ And, given that ROE was an issue worth \$1 million, Staff believed the Commission might easily determine that a zero revenue requirement or even a positive change was necessary. Thus, it is Staff's opinion that a zero change in cost of service on a total company basis will still result in just and reasonable rates.⁸ Instead of a revenue reduction, Staff is now advocating a change from SMRS' current rate design, to a fixed monthly delivery charge for non-gas costs.

Staff originally proposed a ROE of 8.59 percent to 9.39 percent. Because Staff has advocated a zero change in revenue requirement with a new rate design, Staff no longer advocates a particular ROE. Instead, Staff recommends the revenues stay the same.

After reviewing Staff's proposed new rate design, Atmos abandoned its rate increase proposal and is advocating adopting Staff's fixed monthly delivery charge rate design with the slight modification of "seasonal" rates so that the summer charge is less than the winter charge while overall annual revenues stay the same.⁹

⁷ Ex. 104, pp. 1-2; Tr. 99-102, 106-107.

⁸ Ex. 104, p. 2.

⁹ Ex. 6, p. 3; Ex. 7, p. 2.

Public Counsel recommends that the Commission find that rates should be reduced¹⁰ based upon the initial revenue requirement position of the Staff. Public Counsel did not file any direct testimony in this case regarding the overall revenue requirement. Public Counsel also has not filed a complaint against the reasonableness of Atmos' existing rates.¹¹

The Commission finds, based on the evidence regarding rate of return and the positions of the parties, that regardless of the rate design, no change in cost of service, on a total company basis, is necessary to produce just and reasonable rates. As a result, the Commission finds that the answer to subpart c of this issue – What is the appropriate level of revenue excess/deficiency? – is zero. Having made this determination, the first two subparts of this issue (a. What is the appropriate level of expense? and b. What is the appropriate rate of return/return on equity?) are rendered moot. Nevertheless, the Commission will address Public Counsel's position on these issues.

Public Counsel's witness, Mr. Trippensee, sponsored cost of common equity rebuttal testimony suggesting that the Commission use a seven percent OI b in this proceeding if Staff's rate design proposal is adopted. Public Counsel believes this reduction in OI b is necessary to offset the corresponding elimination of weather variability and other business risk for Atmos. Mr. Trippensee attempted to quantify the risk reduction that he believed was associated with the fixed delivery charge rate

¹⁰ Tr. 626-627.

¹¹ Tr. 557.

design.¹² However, as explained further below, the seven percent ROE was calculated using a methodology which is very problematic and is not a method typically relied on by experts in the field.¹³

Both Atmos and Staff's witnesses on this issue, Dr. Donald A. Murry and Mr. Matthew Barnes, thoroughly rebutted Mr. Trippensee's proposal and established that such recommendation was not supported by any commonly accepted rate of return analysis.¹⁴ Mr. Trippensee was also unable to offer any authority in support of his methodology, which Dr. Murry described as "most unorthodox opinion."¹⁵ Furthermore, Mr. Trippensee "did not analyze the first of common equity of companies that may have similar risk characteristics as those that may exist in the first for Atmos' Missouri operations"¹⁶ and "did not even recognize that many of [Staff's] . . . comparable companies have weather mitigation rate designs that minimize risks related to changes in the weather."¹⁷

As Dr. Murry explained in detail in his Rebuttal Testimony and on the witness stand, contrary to the criticism that Staff's analysis does not consider the decreased business risk associated with its proposed rate design, seven of the eight companies that Mr. Barnes identified as comparable to Atmos operate under some type of revenue stabilization mechanisms for their residential and small commercial

¹² Ex. 203, p. 11.

¹³ Tr. 179-180.

¹⁴ Ex. 15, Ex. 102.

¹⁵ Ex. 15, p. 3.

¹⁶ Ex. 102, p. 2.

¹⁷ Ex. 102, p. 2.

customers.¹⁸ In addition, Mr. Barnes confirmed that there was no need for further reduction in his recommended ROE because risk is already reflected in his comparable group analysis.¹⁹ The evidence also revealed that Atlanta Gas and Light, one of the comparable companies, has a rate design similar to what Staff is proposing in this case. That company has been authorized a 10.9 percent return on equity.²⁰ Mr. Barnes further testified that Staff set a "range" of ROEs in this case, as it typically does, which covers a variety of risks affecting the companies.²¹

The Commission finds that Mr. Barnes' analysis of comparable companies includes some degree of risk reduction based on the fact that most of the companies have weather mitigation elements. While Mr. Trippensee had some valid arguments about the need for risk to be considered, his proposed ROE was not reasonable and the Commission finds his methodology to be unreliable.

Based on all the foregoing evidence, the Commission finds that there is zero net additional revenue requirement necessary in order for Atmos to achieve its stipulated gross annualized revenue of \$15,507,737. The Commission finds that rates designed to produce a zero net revenue increase are just and reasonable in that they meet the companies' operating expenses and, based on the analysis of Staff of comparable companies, allow an opportunity to earn a reasonable return on the value of the private property dedicated to public service.

¹⁸ Ex. 15, pp. 4-6; Tr. 89-90.

¹⁹ Tr. 598.

²⁰ Tr. 512, 592.

²¹ Tr. 610-611.

This finding that no change in revenue requirement is necessary does not mean, however, that the Commission accepts Staff and Atmos' fixed delivery charge rate design proposal *carte blanche*. Rather, as will be explained below, the Commission has determined that a fixed delivery charge is not acceptable without a substantial energy efficiency and conservation program.

2. **What is the appropriate treatment of depreciation and should depreciation expense be reduced by a depreciation reserve amortization?**

Record Keeping and Reporting

Depreciation Record Keeping and Reporting has been settled in accordance with the Mutual Non-Unanimous Stipulation and Agreement.²²

Depreciation Reserve Amortization

Staff and Atmos have proposed a negative amortization of the depreciation reserve in the amount of \$591,000.²³ This approach would be implemented by entering a negative amortization of \$591,000 into the depreciation reserve account 108. This would provide an immediate benefit to Atmos' customers by lowering Atmos' depreciation expense to a level that Staff believes is appropriate.

Public Counsel objects to this negative amortization based on Atmos providing insufficient data for the Staff to perform an accurate depreciation analysis.²⁴ Public Counsel also objects because it argues that the negative amortization will require Atmos to reinvest moneys already paid by ratepayers in order to reduce current rates,

²² Section VI, page 5 and Attachment B.

²³ Tr. 188.

²⁴ Ex. 107, p. 8.

and will require the customers to pay a return "on and of" these amounts in future rates.²⁵

Staff's witness, Mr. Gilbert, testified that he was unable to verify the accuracy of Atmos' data and records and "accepted [Atmos] management's recognition and acknowledgment of an over-accrual of depreciation."²⁶ Mr. Gilbert admitted that future ratepayers would be required to repay the \$591,000²⁷ but testified that ratepayers would pay less with the negative amortization than they would pay in rates with different depreciation rates. Mr. Gilbert gave the following example:

[I]f we were to use an example of 1M percent for the return on equity for that additional \$591,000 of rate base, it would cost ...[the ratepayers] \$59,100 a year as opposed to savings of \$591,000 a year in depreciation expense. So, the difference of those two would be the net savings to the current ratepayers.²⁸

Although there might be different methods of achieving the same goal, with the negative amortization, future rates to customers will be less than if the \$591,000 was reflected in lower depreciation rates.²⁹ This method of amortization has often been used by both Pstaff and other utility companies to offset depreciation over- and under-accruals in reserve account 1MB. In this instance, the amortization would offset an over-accrual to the depreciation reserve.

The Commission finds that, as a whole, the annual depreciation accrual should be reduced by approximately \$591,000. The Commission further finds that

²⁵ Ex. 203, p. 13.

²⁶ Tr. 188-189.

²⁷ Tr. 200-201.

²⁸ Tr. 200.

²⁹ Tr. 200.

entering a negative amortization of \$591,000 to the depreciation reserve account provides an immediate benefit to \$tmos' customers by lowering \$tmos' depreciation expense. The Commission finds that the benefits of the negative amortization outweigh any potential harm and that the negative amortization is therefore just and reasonable.

3. What is the appropriate rate design?

- a. What is the appropriate rate structure for residential, small, and medium general service?
- b. What is the appropriate structure for the small general service rate (including the medium general service rate if the small general service class is split)?

Rate Design

\$tmos currently has a "traditional" residential base rate design consisting of a customer charge and a volumetric rate. Under the traditional rate design, residential non-gas margin costs are collected using both a monthly customer charge, which does not vary with usage, and a volumetric charge levied on each Ccf consumed.³⁰ Non-gas margin costs make up only a portion of a residential customer's total monthly bill. The actual gas cost portion of the bill, called the purchased gas adjustment or PG&A, makes up the rest. For the average customer, this is about 80 percent of the total.³¹

In the current case, Ptaff has proposed a shift from the traditional two-part base rate design to a design in which all non-gas costs are recovered in one fixed monthly charge. This type of fixed delivery charge is often termed a "straight fixed variable" rate design.³²

³⁰ Tr. 317.

³¹ Tr. 78.

³² Tr. 694-695; Tr. 85.

For residential and small general service classes Staff recommends recovering the entire amount of the non-gas, or margin, costs in a fixed monthly delivery charge.³³ Staff believes this proposed rate structure will address two significant current issues affecting the natural gas distribution market: 1) remove disincentives for utilities to encourage and assist customers in making conservation and efficiency investments; and 2) reduce the effects of weather on utility revenues and customer bills.³⁴

Under Staff's proposal, each of Atmos' three service areas, Western Missouri (Western EMI), Northeast (NEMI), and Southeast (SEMI), would have a unique fixed delivery charge that is based, per the Agreement, on the revenues generated by the current residential customers within that geographic service area.³⁵ Staff's proposed fixed monthly delivery charges are as follows.³⁶

SEMI (includes Neelyville)	\$13.92 / month
Western EMI (Butler and Deereley)	\$19.43 / month
NEMI (Hicksville; Malmyra; Hannibal; Canton; Bowling Green)	\$20.51 / month

Staff argues that maintaining the "status quo" rate structure:

1. forces residential customers whose usage is greater than the average to pay more than the cost required to serve them, while allowing smaller customers to underpay their cost-of-service;
2. discriminates between identical residential customers in contiguous districts by charging different non-gas margin rates;

³³ Ex. 110, p. 9.

³⁴ Ex. 110, pp. 9-10.

³⁵ Staff Witness Tom Imhoff performed the Class Cost of Service study (Imhoff Direct p. 3-8). The parties agreed to no revenue shifts among the classes and to billing determinants (Attachment A, representing the weather-normalized class test year revenues) in the Partial Non-Unanimous Stipulation and Agreement filed November 29, 2006.

³⁶ Ex. 137; Ex. 7, Schedule PJC SURREB 1.

3. creates unnecessary volatility in customer bills by collecting a larger portion of customers' cost-of-service in the winter;
4. provides no incentive for utilities' to aggressively promote customer efficiency and conservation to their customers; and a utility doing so would be acting contrary to its shareholder interests;
5. sends incorrect price signals to Residential customers; and
6. does nothing to address Senate Bill 179.³⁷

Atmos' original rate design proposal embodied a weather normalization adjustment. However, Atmos' witnesses testified that after careful consideration of the Staff's rate design proposal, Atmos supports the adoption of the Staff's rate design recommendations in lieu of the weather normalization adjustment.

As Staff's witness, Ms. Moss, testified, there is a "rapidly-changing environment" with regard to natural gas distribution.³⁸ Ms. Moss explained that "[a]pproximately five years ago, natural gas prices increased dramatically, and did not return to their previous levels."³⁹ This increase in prices caused residential customer bills to double. In addition, the non-gas portion of a customer's bill went from being approximately 6 percent of the total monthly bill to being approximately 24-25 percent of the total monthly bill.⁴⁰

In addressing the fixed delivery charge rate design proposal, Ms. Moss explained that the Staff rationale has changed over the years. And, that on a national basis, there has been much discussion about conservation and "decoupling," or

³⁷ Ex. 111, p. 6.

³⁸ Ex. 111, p. 5.

³⁹ *Id.*

⁴⁰ *Id.*

separating the delivery costs from the volumetric costs.⁴¹ Ms. Ross specifically references a November 2005, National Association of Regulatory Utility Commissioners (NARUC) *Resolution on Energy Efficiency and Innovative Rate Design*.⁴² That resolution calls for state commissions and other policy makers to consider new rate designs that will encourage energy conservation and energy efficiency.

Public Counsel opposes staff's rate design proposal and advocates maintaining the status quo. Public Counsel argues that the fixed delivery charge rate design is harmful to consumers because: (1) the effect of the proposal is truly not known without sufficient studies; (2) customer efforts to conserve energy will be negated; (3) no conservation or efficiency programs have been introduced; and (4) it will be contrary to good public policy in that it will shift a substantial portion of the cost to the lowest use customers.⁴³

The Commission has set natural gas rates as a two-part base rate for many years and found those rates to be just and reasonable. There is no way of knowing 100 percent of the effects a fixed rate design will have on the ratepayers without having actually experienced such a design. However, the Commission finds the decision by Atmos to abandon its request for a \$P.4 million revenue increase in its entirety is sufficient reason to overcome any doubts about the proposed rate design. Especially when considering that even a portion of that revenue increase, if found just and reasonable, could have a traumatic effect when spread out over the approximately

⁴¹ Tr. 448, 453.

⁴² Ex. 110, Schedule 3-1.

⁴³ Tr. 57-58.

60,000 customers served by Atmos. The Commission further finds that such a rate design is worthwhile so long as it is accompanied by an energy conservation program.

The current rates are designed with a conservation incentive "built in" in that the less gas a customer uses the less that customer will pay. The current rate design encourages conservation by increasing the minimum monthly bill paid by the customer. The rationale is that customers will notice a change in their fixed monthly bill charge and adjust their behavior appropriately. Requiring the company to initiate a conservation program is further insurance that the fixed delivery charge rate design will promote conservation. Thus, in order to change the rate structure, the Commission finds that a conservation program of significant size would be necessary to offset any loss of traditional rate design conservation incentive.

The evidentiary record rebuts Public Counsel's second argument. Under Staff's rate design, customer efforts to conserve energy will not be negated. Eighty percent of a customer's total bill is purchased gas cost.⁴⁴ Even under Staff's proposed rate design where the volumetric portion of non-gas cost is removed in favor of a fixed delivery charge, the customer is still going to have a great incentive to reduce consumption in order to reduce 80 percent of that customer's bill. Thus, consumption is going to be largely driven by the wholesale cost of gas. In addition, by removing the disincentive that Atmos has for encouraging consumption, there is the potential for even greater conservation and efficiency to occur through a comprehensive program funded by the company.

⁴⁴ Tr. 68-69.

Public Counsel next argues that no conservation or efficiency programs have been introduced. Public Counsel's argument is not accurate. It would be more accurate to say that Atmos has not introduced a sufficient program. With the change in rate design, Atmos has committed to spend \$78,000 for low income weatherization (\$2,600 per household for PO customers) and has agreed to institute a residential efficiency audit program for all residential customers (approximately 50,000) – not just low-income customers.⁴⁵ The audit program will cost the customer \$25, and Atmos will pay the additional cost of the estimated \$60 to \$100 total cost per audit.⁴⁶ Atmos witness, Patricia Childers, also testified that Atmos will participate in collaborative meetings with Staff and Public Counsel to provide any further "details" that may be necessary.⁴⁷

Public Counsel did not come forward in this proceeding with any weatherization or efficiency proposals that could assist in encouraging energy conservation or efficiency. Further, Ms. Eisenheimer makes it clear that no conservation proposals would be presented by Public Counsel in connection with the Staff's rate design proposal.⁴⁸ Ms. Eisenheimer also testified that she could not support any fixed delivery charge that recovered 100 percent of the non-gas cost.⁴⁹ Ms. Eisenheimer did state, however, that she agreed that this type of rate design could be just the "carrot" to involve companies in energy conservation programs.⁵⁰

⁴⁵ Tr. 344, 347; Ex. 7, p. 6.

⁴⁶ Tr. 348.

⁴⁷ Ex. 7, p. 6; Tr. 494.

⁴⁸ Tr. 549.

⁴⁹ Tr. 480-481.

⁵⁰ Tr. 545-546.

Finally, Public Counsel asserted that the delivery charge proposal will be contrary to good public policy in that it will shift a substantial portion of the cost to the lowest use customers. The customer demographics for Atmos regarding average residential annual Ccf usage, along with the annual Ccf consumption for various typical residential end-uses, is depicted on Staff Exhibit 142. Exhibit 142 shows that space heating is the major area of consumption at 640 Ccf annually. The next largest area of consumption is water heating at 288 Ccf, gas fireplace inserts at 84 Ccf, and then gas cooking stoves at 24 Ccf.⁵¹ However, the evidence shows that currently the low-use customer is being subsidized.⁵² For example, Ms. Ross testified that a customer who uses gas only for cooking will have the same equipment (meters and pipes) as a customer using natural gas for space heating, heating water, and cooking.⁵³ The Commission finds that the cost of serving a residential customer is the same regardless of the customer's usage. But under the status quo, customers using less than the average will underpay their cost-of-service, while customers using more than the average will overpay their cost-of-service. Staff's fixed delivery charge rate design provides a "barrier" (through standardization) to get Atmos involved in energy conservation programs. However, in this case the Commission does not find sufficient resources of the company being dedicated to replacing the lost incentives for conservation provided by the traditional rate design. Atmos must give consideration for the decreased risk that it will have under a rate design which completely eliminates weather volatility. Atmos has done that by forgoing its request for an additional \$3.4 million. And, Staff's

⁵¹ Tr. 36-37.

⁵² Tr. 304-305

⁵³ Tr. 355-356.

comparable companies include some elements of risk within the analysis. However, that is not enough.

The proposed fixed monthly rate design will eliminate the inherent conflict between the shareholders (whose returns increase if more gas is sold) and the ratepayers (who will only pay less by using less). Thus, the potential for a significant program is there. The Commission also acknowledges the pledge of a \$78,000 low-income weatherization and the unlimited \$25 energy audits that the shareholders are willing to provide as a step in the right direction. However, there was no evidence to suggest that these measures will be sufficient and no details were presented as to how the programs would be implemented. The Commission cannot find that Atmos and Staff have shown that the fixed delivery charge rate design as presented will encourage efficiency and conservation.

As Public Counsel points out, based on the specific facts of other cases, the Commission has previously determined that “[h]igh fixed monthly customer charges tend to defeat customer efforts to reduce their bill by conserving natural gas. As a result, . . . the public interest is best served by setting customer charges as low as reasonably possible.”⁵⁴ However, the natural gas distribution business has changed drastically in less than a decade. It continues to evolve and as such, the Commission must be able to recognize an opportunity to evolve as well. And, as the NAERC resolution states, there is a need for state commissions to do more to promote reduced energy demand and consumption. The Commission is also aware of other programs implemented by other Missouri companies referred to in this proceeding and in other

⁵⁴ Report and Order, *In the Matter of Missouri Gas Energy's Tariffs to Implement a General Rate Increase for Natural Gas Service*, Case No. GR-2004-0209, September 21, 2004.

states as evidenced by the information provided in Exhibit 144. The Commission finds that a comprehensive energy efficiency and conservation program can work to provide benefits to the ratepayers and to the general public interest by reducing the demand and consumption of natural gas.

The Commission finds that under the circumstances of this case, Atmos' rates are ripe for being redesigned. However, the Commission cannot find such a design to be in the public interest without some assurance of a significant energy conservation and efficiency program that will educate and assist Atmos' customers in conservation and reduced demand. In this instance the Commission has determined that with the right conservation and efficiency program, a fixed delivery charge would be in the public interest while allowing Atmos a fair return on its investment.

Atmos has proposed A78,000 and unlimited energy audits creating a minimum of A1.75 million⁵⁵ worth of potential liability. Obviously, not every one of the 50,000 residential customers served by Atmos will request an audit. However, that commitment shows that Atmos is capable and willing to provide enough funding to implement a meaningful conservation program. Thus, the Commission finds that it would be just and reasonable and in the public interest to implement a fixed delivery charge rate design as proposed by Staff on the condition that Atmos contribute annually, one percent (1%) of its annual gross revenues (currently, approximately A165,000) to be used for an energy efficiency and conservation program.

If Atmos does not provide for such a program, the Commission cannot find that the proposed rate design is just and reasonable and in the public interest and

⁵⁵ Approximately 50,000 residential customers multiplied by a minimum of \$35 per possible audit requested.

therefore, the Commission must reject it. In that event, the Commission determines that it is just and reasonable and in the public interest to maintain the status quo rate design and that no party has justified a change in the revenue requirement.

The Commission finds that an energy and conservation program must be approved by the Commission and must be the result of a collaborative process involving the Staff, Public Counsel, Atmos, the other parties to this case (that wish to participate), the Energy Center of the Missouri Department of Natural Resources, and other parties that the Commission shall designate. As the Commission has found with regard to other companies, a successful program may include Energy Star education and communication, appliance rebate and replacement, green construction for old and new homes, Pay As You Save programs, weatherization, energy audits (with follow-up), and others. Such a program may contain a low-income component as well as residential, commercial, and industrial components. The comprehensive program should be designed with methods for gathering and reporting data to analyze its effectiveness.

Therefore, the Commission directs that if Atmos files tariff pages in compliance with this order designed to implement a fixed delivery charge, it shall also set up a new program by meeting with the other parties set out above, and any other social service agency or party that the Commission designates to participate, and design a program to be approved by the Commission and implemented no later than August 31, 2007. The Commission will direct that Atmos file a report regarding the status of any collaborative effort every thirty days. In addition, Atmos must present a program for Commission consideration no later than June 30, 2007. Finally, if the fixed delivery charge rate design is implemented, Atmos shall file on an annual basis a report with the

Commission for the purpose of evaluating the effect of a fixed delivery charge rate design on energy efficiency and conservation.

If Atmos does not file tariff pages designed to implement a fixed delivery charge rate design, it shall file new tariff pages designed to implement the status quo rate design with the other changes as set out in this Report and Order.

The Commission will issue further orders following this Report and Order to set up the collaborative process to design the conservation program if necessary.

Seasonal Rates

Atmos recommends one modification to the Staff proposal by seasonally "sculpting" the fixed monthly delivery charge.⁵⁶ Atmos proposes that the delivery charge be higher in the winter and lower in the summer. The sculpting of the rates would allow for the same annual revenue projections as Stall's rate design.⁵⁷ Atmos argues that the benefits of its sculpting proposal are that it will reduce the risk of customer loss during the summer months and it will aid in customer acceptance of the changed rate design.⁵⁸

Stall's fixed monthly delivery charge rate design proposal, as modified by Atmos' sculpting rates, is set forth in Schedule GLS-1 as follows:

	<u>Summer</u>	<u>Winter</u>
Butler/Deeley	A15.00	A25.45
Hicksville/Malmyra/Lord R Cd	A15.00	A28.24
Old SEMOL/Neelyville	A10.00	A19.23

⁵⁶ Ex. 3, pp. 4-5, and Schedule GLS-1.

⁵⁷ Tr. 299.

⁵⁸ Ex. 3, p. 4.

As set out below, the Commission finds that the problem of customers disconnecting on a seasonal basis should be solved through the seasonal disconnection charges. While the "sculpted" rates may offer less of an incentive for customers to disconnect in the warmer months, it also would have a significant affect on rates in the winter months. The Commission finds that this disparity is not justified.

Small General Service Rate Class

Ptaff proposes to create new classes of d eneral Pervice customers. The basis for this part of Staff's proposal was the large variation in usage between members of the class. Pome of the d eneral Pervice class use zero Ccfs, and some of them use close to a million Ccfs in one year. Ptaff proposes to split the Pmall d eneral Pervices rate class so that customers using more than 2,000 Ccf per year will retain the traditional rate structure while those at or below 2,000 Ccf will be under the same rates as residential ratepayers. Cor the others, there would be a new Medium d eneral Pervice class, a i arge d eneral Pervice class, and a i arge S olume Pervice class. Ptaff recommended the traditional rate design for those customers.⁵⁹

Pmall d eneral Pervice Customers using less than 2,000 Ccf per year are served with the same meter/regulator and service lines as residential customers. Approximately 80 percent of Atmos' current Small General Pervice customers use less than 2,000 Ccf per year.

The proposed Medium d eneral Pervice class would include non-residential customers using from 2,000 to 75,000 Ccf per year. The i arge d eneral Pervice class would include non-residential customers using from 75,000 to 200,000 Ccf per year.

⁵⁹ Tr. 353-354.

Atmos agrees to accept Staff's proposal to split the general service class and to have uniform classes throughout the state.⁶⁰

Public Counsel believes the Commission should maintain the existing structure for the entire Pmall General Service rate class. Public Counsel's foremost concern with Staff's proposal is that it will create discontinuity within the Pmall General Service class. Under Staff's proposal, General Service customers using 2,001 Ccf will pay two to three times as much in non-gas rates as a customer using 2,000 Ccf.⁶¹

The Commission is not persuaded by Public Counsel's argument. The evidence supports Staff's proposal. Whenever classes are distinguished, there must be a dividing line between those classes. The proposal by Staff is logical in that those customers using less than 2,000 Ccf per year are served by the same size and type of equipment as residential customers. Thus, the Commission finds that a residential delivery charge for Pmall General Service customers using less than 2,000 Ccf per year within the same territory is just and reasonable. The Commission shall adopt the proposal of Staff with regard to this issue.

4. What are the appropriate miscellaneous charges (activation charges for connection, reconnection, and transfer; late payment, NSF, and seasonal reconnection)?

Atmos testifies Michael E. Ellis sponsors Atmos' proposal to make various miscellaneous charges (connection, reconnection, and transfer; late payment; insufficient funds; and seasonal reconnection) uniform and consistent across its

⁶⁰ Ex. 6, pp. 3-4.

⁶¹ Ex. 201, p. 26.

Missouri service area.⁶² Mr. Ellis supports the rates proposed with a cost analysis discussed in, and attached to, his testimony. Staff proposes that these miscellaneous charges be based on the actual costs rounded to the nearest whole dollar.

While Atmos and Staff have reached agreement on all of the issues addressed in the Miscellaneous Charges area, Public Counsel objects to the changes. The exception is for interest paid on customer deposits, a change that would bring parity to all deposits.⁶³ An agreement was also reached to revise Atmos' proposed tariff language and use the generic terminology, instead of the term "activation charge."⁶⁴

Connection, Reconnection, and Transfer Charges

Some areas of Atmos' service territory currently do not have connection, reconnection, or transfer charges. The Commission finds that it is appropriate to make these types of charges uniform within all of Atmos' service territory. In addition, the Commission finds that it is reasonable to align the charges with the actual costs to provide the service.

The actual costs of providing the specific services and applicable rates to be applied on a statewide basis, as agreed to by Atmos and Staff, are:⁶⁵

⁶² Ex. 10, pp. 2-8.

⁶³ Ex. 10, p. 7.

⁶⁴ Ex. 114.

⁶⁵ Ex. 114, pp. 5-6; Tr. 635-636.

<u>Type of Charge</u>	<u>Actual Cost</u>	<u>Proposed Charge</u>
Connection – Normal e ours	\$23.56	\$24.00
Connection – \$ fter Normal Hours	\$50.09	\$50.00
5econnection – Normal Hours	\$23.56	\$24.00
5econnection – \$ fter Normal e ours	\$50.09	\$50.00
7ransfer – Normal Hours	\$20.02	\$20.00
7ransfer – \$ fter Normal Hours	\$46.55	\$47.00

The Commission finds the proposed charges to be just and reasonable based on the actual costs to provide such services and shall adopt them.

NSF Charges

As with the other charges, Staff supports a statewide charge in an amount closely related to the actual costs. Currently, Atmos charges \$N5.00 for an insufficient funds (NSC) charge for approximately 75 percent of its customers.⁶⁶ The rates for the remaining customers have been under cost at \$N0.00 and Staff was able to discern that charge had been applied only twice in the last three years. Thus, for all practical purposes Atmos has had an NSC charge of \$N5.00. Therefore, the Commission finds it reasonable to set these charges on a statewide basis in an amount that is closer to the actual costs. The Commission adopts a statewide NSC charge for Atmos of \$N5.00.

Late Payment Fee

Atmos also requests authority to apply the authorized late payment fee found in specific existing tariff sheets (equal to N5 percent of the outstanding balance) across all rate schedules. The late payment fees existing in \$tmos' 0 issouri tariffs vary in amounts and this change will make the charge consistent across all of \$tmos' 0 issouri

⁶⁶ Ex. 117, p. 2.

service areas.⁶⁷ Staff supports and recommends that the late payment fee be consistent throughout the tariff. Public Counsel only addresses this issue in its Prehearing Brief, where this component is listed with those "miscellaneous charges that remain unresolved between the parties."

The Commission finds that the late payment fee equal to 1.5 percent of the outstanding balance is reasonable and shall be applied on a statewide basis by Atmos.

Seasonal Reconnection

The proposed seasonal reconnection charge is the most contentious of the Miscellaneous Charges. One-tenth⁶⁸ of Atmos' customers disconnect for a month or more each year.⁶⁹ Thus causing Atmos to forgo revenues from its investments to those properties (e.g. meters, pipes, mains, etc.). Staff proposes a two-component reconnection charge to dissuade seasonal customers that disconnect during the non-winter months and do not pay for the costs associated with providing utility service.⁷⁰ Such a customer would pay the traditional reconnection charge (\$24.00 proposed); in addition, the customer would make up all missed delivery charges that occurred while the customer was disconnected. Staff proposes a 12-month limitation to the second component, regardless of the reason for disconnection. The purpose of this change is for the company to make up the revenues lost during the months of disconnection.

⁶⁷ Ex. 10, pp. 5-6.

⁶⁸ Mr. Ensrud testified that 1/10 or 7,000 customers disconnect for a month or more each year. (Tr. 651.) However, other evidence indicates that Atmos only has 60,000 customers. Therefore, the Commission assumes the lower number of customers for the sake of this argument.

⁶⁹ Tr. 651.

⁷⁰ Ex. 114, pp. 18-20.

Otherwise, the company has a certain amount of embedded costs that it cannot recoup unless gas service is being provided to that customer.

Although Atmos proposed seasonally sculpting the rates as a possible way to alleviate some of the seasonal loss concerns, it supports Staff's proposal.⁷¹ Atmos believes that it can recoup sufficient revenue under its sculpted rate proposal without collecting all the missed customer charges. In addition, Atmos' original proposal included a reconnection charge of up to twelve months of a \$9.00 statewide customer charge. Atmos requests that regardless of the methodology chosen, the Commission address this concern.

Public Counsel does not offer any type of adjustment to Atmos' revenue requirement to adjust for seasonal customers, but argues that it is appropriate to allow customers to disconnect during the non-winter months.

Atmos has a provision similar to Staff's proposal in its tariffs for its current PEJ O, Butler, and Hirksville districts.⁷² Those provisions, however, require the payment of the customer charge, and not the volumetric portion, of the missed months where the customer has requested the disconnection.

As the undisputed evidence shows, Atmos has a significant problem with lost revenues due to ten percent of its customer base disconnecting for a month or more and then reconnecting at the same address. Customers seek to avoid paying the fixed cost of providing gas service when not using gas for heat, and thus shift costs for their meters and equipment during that time to the other customers. The Commission finds that a seasonal reconnection charge is a just and reasonable way to discourage

⁷¹ Smith, Ex. 3, p. 4.

⁷² Tr. S. 639 – 640.

seasonal disconnection while allowing Atmos to recover its fixed costs of offering service to the premises.

The Commission further finds, however, that there is not sufficient justification for recovery of Staff's proposed seasonal reconnection charges up to twelve months. The twelve-month recovery of the fixed delivery charge would be a total of up to: \$157.04 (PEMI); \$233.15 (t EMI); and \$247.32 (NEMI). Customers would pay the \$24.00 reconnection fee in addition to the seasonal reconnection charges. The Commission finds that Staff's proposed collection of customer charges for up to twelve months would cause a significant barrier to low-income households trying to get service reconnected for the winter heating season. After carefully examining all the various proposals set forth to solve the seasonal disconnect problem, the Commission is able to find a solution.

The proposal presented to the Commission is for a "seasonal" disconnection charge and all of the evidence suggests that it is customers who disconnect for the warmer months and then reconnect for winter at the same location that cause the issue which needs to be addressed. Thus, Atmos and Pfaff are seeking to discourage those customers who disconnect during the summer season. The "summer season" is clearly meant to be the time period from March 1 to October 31 as defined in the Commission's Cold Weather Rule.⁷³ Therefore, it is unreasonable to make the applicable period for the "seasonal" disconnection charge longer than seven months.

Even with a seven-month cap on the seasonal disconnection charge these fees might be a rate shock for some customers. Because the customers have not

⁷³ 4 CSR 240-13.055.

previously had the higher fixed delivery charge during the summer months,⁷⁴ customers who disconnect on a seasonal basis will be shocked to discover that they must pay as much as \$97.44 (SEMO), \$136.01 (WEMO), and \$144.27 (NEMO), plus the \$24.00 reconnection fee, in order to reconnect service. This is especially significant because in all likelihood those customers disconnected because they could not afford to pay the monthly charge in the summer months.

Given that the Commission has found the recovery of the fixed delivery charges to be a reasonable cost recovery mechanism, the Commission has determined that the rate shock to the customers justifies a further reduction of the amount of recovery in order to mitigate the rate shock to the customers. The Commission determines that customers would not be so shocked by a charge that was one-half of the seven-month summer season. Therefore, the Commission finds that it is just and reasonable to reduce the seven-month cap further by half.

The Commission finds that the seasonal disconnection charge is just and reasonable and in the public interest so long as it is limited to a three-and-one-half-month cap on recovery of the fixed monthly delivery charge. In addition, the Commission finds that this provision should be prospective only. That is, Atmos should not be allowed to recover any reconnection charges that were not in effect at the time of the customer's disconnection.) or example, if Atmos files new tariffs with the fixed monthly charge, it must only charge the customer what it could have charged under the tariff that was in effect for that customer at the time of the disconnection.

⁷⁴ Previous "customer charges" were in the range of \$5.00 to \$9.05.

5. Should Atmos' districts be consolidated for purposes of setting margin non-gas rates in this case?

Atmos currently has six sets of base tariffs and six purchased gas adjustments (PGAs) for its Missouri service areas (although there are seven separate PGA rate filings). The areas are referred to as District B (Butler); District K (Kirksville); District S (Southeast Missouri, all of which are properties formerly operated by Associated Natural Gas Company); District G (Greeley) formerly operated by Greeley Gas Company; District U (Hannibal/Canton/Palmyra/Neelyville) and District P (Palmyra), both formerly operated by United Cities Gas Company. Staff proposes to consolidate base rates into three geographic areas.⁷⁵ A map depicting this proposal was submitted into the proceedings (Exhibit 100). Staff's proposal is very similar to that of Atmos⁷⁶ and is supported by Atmos. OPC opposes this consolidation.

The consolidated rates are supported by staff's cost studies and by the Missouri Gas Service Users' Groups.⁷⁷ The consolidation will combine the current rate districts into three service territories based on location, and will set a single rate for all customers in a particular class in a particular geographic area. By consolidating the districts, customers in neighboring communities will pay similar non-gas rates.⁷⁸

The new areas would be as follows:

- i. NbMO: Kirksville, Palmyra, Hannibal/Canton/Bowling Green
- ii. SbMO: Neelyville and SbMO
- iii. t bMO: Greeley and Butler/Polk Hill

⁷⁵ Ex. 110.

⁷⁶ Ex. 5.

⁷⁷ Tr. 298.

⁷⁸ Ex. 110, p. 4.

Public Counsel opposes consolidating the districts without comprehensive data and cost studies. Public Counsel argues that the embedded costs for each district may not be the same. In addition, Public Counsel argues that customer confusion will result from the widely varying changes in rates as the result of consolidation.

The Commission is persuaded by Stall's evidence that the districts should be consolidated. Ptiff identified what appear to be inequities between users in various districts of Atmos. A customer using T20 Ccf per year would pay annual non-gas costs as follows:⁷⁹

hirksville –	\$138
Palmyra –	\$153
Leannibal/Canton/Bowling Green –	\$259
Greerley –	\$290
Butler –	\$213
Neelyville –	\$259

Thus, Ptiff has shown that customers in neighboring districts pay much different costs for the same gas usage.

The cost for Atmos to serve similarly situated customers in neighboring districts, such as the combining of three adjoining northeast Missouri districts into one service territory, is about the same. Atmos does not buy equipment, such as meters or mains, in quantities intended to serve most one "legacy" district. Atmos service employees serve *all* customers in each of its geographical service areas. Corporate overhead expenses associated with serving a residential customer are also indifferent as to the "legacy" district that customer lives in.

⁷⁹ Tr. 37-39; Ex. 112, pp. 8-9; Ex. 142, p. 7.

While there may be some difference in costs due to the vintage of the distribution equipment in various "legacy" districts at any given point in time, Atmos' costs to provide service today do not change from area to area. Moreover, the cost of meters, regulators, and service lines is the same for all districts. In addition, when a customer calls Atmos customer service, the call is first answered by a Company representative located in one of three out-of-state call centers. If that call cannot be addressed, then it is routed to one of seven Missouri call centers which serve the surrounding area. These calls are routed without regard for the predecessor company that served the area ten years ago. Related billing and customer service costs do not vary among Atmos' current seven districts.

For Atmos to make the attempt to collect and break out its costs to serve each of seven "legacy" districts is unnecessary – particularly in light of the reasonableness of combining these districts into their natural geographic service areas. The Commission finds that it is just and reasonable to consolidate the base rate districts of Atmos as proposed by Staff.

6. Should Atmos' PGA tariffs be consolidated for purposes of setting gas rates in this case?

Staff recommends consolidating Atmos' PGA rate districts, by pipelines served, into the following four districts: (1) Butler and Dreeley; (2) Hannibal/Canton, Bowling Green and Malmyra; (3) Hirksville and (4) PBM and Neelyville.

Butler and Dreeley are combined into one district because their primary source of gas comes from the Mid Continent Basin. As a result, the commodity costs are basically the same, even though the gas is being transported over two different pipelines.

For the SEMO/Neelyville consolidated 3GA district, Staff's witness, Mr. Imhoff, noted that the P&I pipeline currently feeds both Neelyville and a part of SEMO as well, even though SEMO has four different pipelines feeding into it.

At hearing, Mr. Imhoff also testified that Staff will have each individual "3GA" district take care of its respective Actual Cost Adjustment (ACA) balances to "zero them out." The current Earnings are very close with the exception of the ACA factor, which will run for 12 months to recover or refund any over- or under-recovery.⁸⁰ Although Atmos proposed a statewide consolidation for the PdA, its witness testified that consolidation of the four areas identified by Staff's direct testimony is acceptable.⁸¹

Public Counsel opposes PdA consolidation. Public Counsel argues that the rates vary significantly among districts, and the parties have offered no compelling reason other than administrative burden to alter the PdA structure. Gas costs represent 13 percent to 82 percent of a customer's bill and consolidating could have a substantial negative effect on customers in areas with lower rates.

The Commission finds that PdA consolidation as proposed by Staff will simplify and improve the PdA/ACA rate process by making it more efficient as a result of reducing the current number of filings made by Atmos. This is accomplished by logically identifying the PdA computation by pipeline or supply source. New, consolidated PdA districts have similar transportation rates and gas supply sources. Such consolidation is consistent with how other regulated utilities (e.g., AmerenPE) currently file PdA rate filings. In addition, one company is currently doing all gas purchasing for each of the districts, and employing the same hedging program and strategy for

⁸⁰ Tr. 242.

⁸¹ Ex. 6, p. 4.

Missouri. Finally, as Staff's testimony showed, under the current 3GA rates, "the maximum rate differential between the various proposed MDA rate district consolidations . . . [is] \$.0309 per Ccf."⁸² Thus, the effect on customer rates will be insignificant.

In addition, although the four MDA areas do not align exactly (Hicksville is the exception) with the geographic non-gas rates, they are substantially the same in most areas and, therefore, the benefits of bill comparability will be achieved if the Commission adopts the four areas as recommended by Staff. The Commission finds the MDA consolidation to be reasonable and shall adopt Staff's proposal.

7. Other Tariff Issues:

- a. Should a cash-out policy be implemented?
- b. Should the Commission allow third-party administered pools for cash-outs?
- c. What is the appropriate level of lost and unaccounted gas?
- d. Should the Commission approve an Economic Development Rider?
- e. Should the mains extension policy and the determination of amounts to be charged be changed in this case?

Cash-Out Policy

The cash-out provision allows transportation customers to resolve imbalances by cash payments instead of making up imbalances with gas volumes in kind. This provision replaces Atmos' existing policy of charging \$15.00 per Mcf when the balance is negative, or absorbing the gas when the imbalance is positive. Whether the imbalance is positive or negative, a transportation customer will pay a price determined by a formula that uses a published industry price. If the imbalance is greater than 5 percent of the monthly contract volume, the price will be inflated or deflated by an index referenced in the tariff. This standardized policy will replace Atmos' current

⁸² Ex. 120, p. 2.

practice of applying varying policies. Atmos also agrees to make minor changes to the transportation tariffs.

Public Counsel's only opposition noted in testimony is that large transportation customers would be allowed to create pools that would allow pool members to offset imbalances, thus allowing large volume customers flexibility at smaller ratepayer expense. According to Ptaff, the only customers on Atmos' system that could pool are the school districts, which are allowed to pool by statute.

The Commission finds that it is just and reasonable to have a standardized policy regarding cash-outs. Furthermore, there was no evidence that this policy will affect any customer or revenues of Atmos in any manner, other than school districts which all allowed to pool under current Missouri statutes. Thus, the Commission finds in favor of Atmos on this issue.

Third-Party Administered Pools for Cash-Out

Atmos proposes to allow third parties to create pools that would allow pool members to offset imbalances caused by transport customers taking more or less gas from the system than the amount under contract. According to Ptaff, the only customers on Atmos' system that could pool are the school districts which are already allowed to pool by Section 393.310, RSMo. Public Counsel has the same concerns as with the Cash-Out issue above.

For the reasons stated above, the Commission finds in favor of Atmos' proposal.

Level of Lost and Unaccounted Gas

The issue of the level of lost and unaccounted gas has been settled among the parties and is addressed in the Partial Non-Unanimous Stipulation and Agreement.⁸³

Economic Development Rider

An Economic Development Rider (EDR) encourages industrial customers to use Atmos' natural gas service by providing limited discounts.⁸⁴ Staff carefully analyzed the proposal and recommended that it be adopted.⁸⁵

Eric Crunsel's testimony that the EDR would force residential and small customers to subsidize industry discounts is unsubstantiated and contrary to Staff's analysis indicating that generally, a new industrial customer will generate revenues and defray costs beyond the initial discounted amounts.

The Commission is persuaded by Mr. Ensrud's Substantive testimony regarding this matter.⁸⁶ He testifies that a new customer will generate revenues and defray fixed costs to the point that both Atmos stockholders and ratepayers will benefit.⁸⁷ In addition, Mr. Ensrud testifies that secondary benefits of the potential economic development, such as new jobs, new tax revenue, and increased property values are also to be taken into consideration. The Commission finds that it is just and reasonable and in the public interest to allow an EDR as proposed by Atmos. The Commission finds for Atmos with regard to this issue.

⁸³ Stipulation, page 5; see also, Staff's Memorandum in Support of the Stipulation, p. 4.

⁸⁴ Ex. 9.

⁸⁵ Ex. 114.

⁸⁶ Ex. 115, pp. 9-11.

⁸⁷ Ex. 114, p. 1M

Mains Extension Policy and the Determination of Amounts to be Charged

Atmos proposes to eliminate its current minimum line extension policy. Currently, customers may receive up to 150 feet of gas main extension free. Instead, Atmos would use a computer model to estimate the cost of the main and the revenue that will be produced. The initial customer would be compensated by the utility if additional customers come on to the extended portion of the main.⁸⁸ Staff proposes one exception with regard to relunds, but otherwise agrees with Atmos' proposal.

Public Counsel opposes Atmos' proposal to eliminate the minimum line extension, and subject every new residential and small business customer to a feasibility review resulting in an up-front fee for main extensions. "A reasonable fee-free line extension is both a reasonable obligation to impose on a public utility and an investment in future earnings for the utility."⁸⁹

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

Conclusions of Law

The Missouri Public Service Commission has arrived at the following conclusions of law.

⁸⁸ Ex. 114, p. 13-14.

⁸⁹ Ex. 202, p. 38-39.

Jurisdiction

Atmos is a public utility, and a gas corporation, as those terms are defined in Section 386.020(42) and (18), RSMo 2000. As such, Atmos is subject to the Commission's jurisdiction pursuant to Chapters 386 and 393, RSMo.

Burden of Proof

Section 393.130.2, RSMo 2000, provides in part, "At any hearing involving a rate sought to be increased, the burden of proof to show that the increased rate or proposed increased rate is just and reasonable shall be upon the . . . gas corporation . . . and the commission shall give to the hearing and decision of such questions preference over all other questions pending before it and decide the same as speedily as possible."

Commission's Authority

Pursuant to Section 393.130.1, RSMo 2000, the Commission has authority to prohibit the implementation of gas rates that are unjust or unreasonable.

Section 393.140 authorizes the Commission to determine just and reasonable rates. Section 393.130, in pertinent part, authorizes the Commission to suspend for a period of time any schedule stating new rates, charges, rules, regulations, or practices, and to hold "a hearing concerning the propriety of such rate, charge, . . . rule, regulation or practice." Section 393.270 provides in paragraph 4 that in determining the price to be charged, "the commission may consider all facts which in its judgment have any bearing upon a proper determination of the question" The courts have held that this statute

means that the Commission's determination of the proper rate must be based on consideration of all relevant factors.⁹⁰

In determining whether rates are just and reasonable, the Commission must balance the interests of the investor and the consumer.⁹¹ The Commission's failure to establish just and reasonable rates would, in fact, violate the United States Constitution. In discussing the need for a regulatory body to institute just and reasonable rates, the United States Supreme Court has held as follows:

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 services are unjust, unreasonable and confiscatory, and their enforcement deprives the public utility company of its property in violation of the Fourteenth Amendment.⁹²

In the same case, the Supreme Court provided the following guidance on what is a just and reasonable rate:

That 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

⁹⁰ *State ex rel. Missouri Water Co. v. Public Service Comm'n*, 308 S.W.2d 704, 719 (Mo. 1957); *State ex rel. Midwest Gas Users' Ass'n v. Public Service Commission*, 976 S.W.2d 470, 479 (Mo. App., W.D. 1998); *State ex rel. Office of Public Counsel v. Public Service Com'n of Missouri*, 858 S.W.2d 806 (Mo. App., W.D. 1993).

⁹¹ *Federal Power Commission v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1943).

⁹² *Bluefield Water Works and Improvement Company v. Public Service Commission of West Virginia*, 262 U.S. 679, 690 (1923).

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.⁹³

In undertaking the balancing required by the Constitution, the Commission is not bound to apply any particular formula or combination of formulas. Instead, the Supreme Court has said:

Agencies to whom this legislative power has been delegated are free, within the ambit of their statutory authority, to make the pragmatic adjustments which may be called for by particular circumstances.⁹⁴

The dominant purpose in creation of the Commission is public welfare.⁹⁵ Section 386.610 reads, in relevant part, that "[t]he provisions of this chapter shall be liberally construed with a view to the public welfare, efficient facilities and substantial justice between patrons and public utilities." The Commission must weigh the benefits and detriments to all the groups affected by its decision.

Under Section 386.270, 90 S.Mo. 2000, all rates of a public utility that have been approved by the Commission are prima facie lawful and reasonable until found otherwise in a suit brought for that purpose pursuant to the provisions of Chapter 386.

DECISION

Stipulation And Agreement

Atmos, the Staff, and Public Counsel filed on November 29, 2006, their *Partial Non-Uniform* Stipulation and Agreement, which sets forth issues settled among the parties.

⁹³ *Id.* at 692-93.

⁹⁴ *Federal Power Commission v. Natural Gas Pipeline Co.* 315 U.S. 575, 586 (1942).

⁹⁵ *Alton R. Co. v. Public Service Commission*, 110 S.W.2d 1121, 1125 (Mo. App. 1937).

Pursuant to 4 CSR 240-2.115(2)(C), because no parties objected within seven days to the Partial Non-Unanimous Stipulation and Agreement, the Commission may, by operation of law, treat this Agreement as a unanimous stipulation and agreement.

The Stipulation addressed the following issues as resolved among the parties: Billing Determinants; Other Post-Retirement Benefits (OPEB) Contribution; Class Share of Revenue by District / Class Cost of Service; Customer Service Requirements and Reporting; PGA Minimum Filing Requirements; Depreciation Record Keeping and Reporting; and Gas Loss Reporting.

Based on the agreement of the parties, the Commission concludes that the Agreement constitutes a just and reasonable settlement of all of the issues included therein.

Contested Issues

1. Revenue Requirement

- a. Level of Expense
- b. Rate of Return / Return on Equity
- c. Level of Revenue Excess / Deficiency

The Commission concludes that rates designed to produce a zero net revenue requirement allowing for a stipulated gross annualized revenue of \$16,507,737 are just and reasonable in that they meet \$t p rs' su Gnt p se u ating expense and allow an opportunity to earn a reasonable return on the value of the private property dedicated to public service.

2. Depreciation and Reserve Amortization

The Depreciation issues are resolved among the parties in accordance with the Stipulation, which constitutes a just and reasonable settlement of the issues.

The Commission concludes that, as a whole, the annual depreciation accrual should be reduced by approximately \$591,000 and that, by Atmos entering a negative amortization of \$591,000 to the depreciation reserve account, this provides an immediate benefit to \$tmos' customers by lowering \$tmos' depreciation expense. The Commission concludes that based on these facts, this is a just and reasonable result.

3. Rate Design

Based on the specific facts in this case, the Commission finds that placing all non-gas costs into a fixed delivery charge, within the context of a zero revenue increase and the consolidation of the operating districts into three service areas (NbMI , t bMI , and PbMI) will provide for just and reasonable rates *if* it is accompanied by a meaningful energy efficiency and conservation program as described above. Thus, the Commission concludes that no party justified a change in revenue requirement, and absent the conservation program, the Commission must reject the proposed fixed delivery charge rate design. *ff* Atmos chooses to enter into a significant energy efficiency and conservation program as set out in this order to be approved by the Commission, it may file tariffs including a fixed delivery charge rate design.

The Commission determines that the problem of seasonal disconnects is most appropriately handled in the context of a seasonal disconnection charge. Thus, the Commission concludes the proposed seasonally "sculpted" rates are not ~~M~~st and reasonable.

The Commission further concludes that creating a Pmall d eneral Pervice class that is based on the same operating parameters and cost of service of the Residential class provides just and reasonable rates for non-residential customers.

The Commission also concludes that maintaining the traditional rate design for Medium General Service and Large General Service customers provides just and reasonable rates to the members of these service classes.

4. Miscellaneous Charges

The Commission concludes that uniform, statewide cost-based charges for Activation, Reconnection, Transfer, Late Payment, and NSF are just and reasonable.

The Commission concludes that the "seasonal" reconnection charge is a just and reasonable method of discouraging customers from disconnecting from the system on a seasonal basis. In addition, the seasonal reconnection charge will allow Atmos to recover its fixed costs of serving the customer and prohibit the shifting of costs from the customer who disconnects to all other customers. The Commission further determines, however, that for the charge to truly be a "seasonal" reconnection charge, it cannot reasonably recover more than seven months of the fixed monthly charge. The Commission further determines that the recovery of up to seven months of a fixed monthly delivery charge would be so shocking to customers attempting to reconnect as to be unreasonable. Therefore the Commission determines that the recovery of the fixed monthly delivery charge for the purpose of a seasonal reconnection fee should be limited to three-and-one-half months. In addition, Atmos shall only collect the seasonal disconnection charge on a prospective basis.

5. Company PGA Tariffs Consolidation

The Commission concludes that the consolidation to four PGA districts provides for just and reasonable rates because the consolidation is based on the cost

similarity of interstate pipelines that serve the districts and/or the cost similarity of the sources of gas supply to the districts.

6. Company District Consolidation

Because the costs to provide service to each service area do not change among those areas, the Commission concludes that the consolidation of operating districts into three geographic service areas (NEMO, WEMO, SEMO) for the purpose of setting non-gas margin rates (the fixed delivery charge) provides for just and reasonable rates.

7. Other Tariff Issues

The Commission concludes that the Cash-Out Policy and the Economic Development Gas Service Rider provide for just and reasonable rates and that no credible evidence opposing these tariff issues has been provided by Public Counsel.

The Commission concludes that Third-Party Administered Pools for cash-outs provide for just and reasonable rates and notices that school districts are permitted to pool under Section 393.310.

The Lost and Unaccounted Gas issue is resolved among the parties in accordance with the Stipulation, which constitutes a just and reasonable settlement of this issue.

With regard to the main extension policy proposed by Atmos and Staff, the Commission concludes that it is not a just and reasonable policy, and therefore it must be rejected.

CONCLUSION

The Commission has thoroughly considered the facts of this case and the arguments of all the parties. The Commission has found that the status quo rate design is just and reasonable and that the volumetric rates encourage conservation. The Commission agrees with its Staff that the facts of this case present an opportunity to implement just and reasonable rates under a rate design that is quite novel in the state of Missouri. However, the Commission has determined that it is not just and reasonable to relinquish the conservation measures currently in place in the form of volumetric rates without also implementing a significant efficiency and conservation program to offset the loss of conservation encouraged by the volumetric portion of the rate. Therefore, the Commission has determined that Atmos shall maintain the status quo rate design unless it proceeds with a significant energy efficiency and conservation program as set out in the body of this order. If Atmos chooses to go forward with such a program, it may file new tariffs designed to implement not only that program, but also a fixed delivery charge rate design.

IT IS ORDERED THAT:

1. Exhibit 144 is admitted into evidence.
2. All pending motions and requests for relief not otherwise granted are denied.
3. The Partial Non-Unanimous Stipulation and Agreement filed on November 29, 2006, is hereby approved as a resolution of all issues contained therein (See Attachment A).

4. The parties are ordered to comply with the terms of the Stipulation and Agreement.

5. The proposed gas service tariff sheets (Tariff No. YG-2006-0762) submitted on April 7, 2006, by Atmos Energy Corporation for the purpose of increasing rates for gas service to retail customers are rejected. The tariff sheets rejected are:

P.S.C. MO. No. 2

Original Sheet No. 1 through Original Sheet No. 113

6. Atmos Energy Corporation may file tariffs that comply with this Report and Order.

7. If Atmos Energy Corporation files tariffs that include a fixed delivery charge rate design, it shall also set up an energy efficiency and conservation program as outlined in the body of this order to be implemented no later than August 31, 2007, and shall present a program to the Commission for consideration no later than June 30, 2007 .

8. If Atmos Energy Corporation files tariffs that include a fixed delivery charge rate design, beginning on April 1, 2007, Atmos shall report to the Commission no later than the first day of every month as to the status of the collaborative process set out herein.

9. If Atmos Energy Corporation files tariffs that include a fixed delivery charge rate design, it shall file on an annual basis a report with the Commission for the purpose of evaluating the effectiveness of a fixed delivery charge rate design on energy efficiency and conservation.

10. This Report and Order shall become effective on March 4, 2007.

BY THE COMMISSION



Colleen M. Dale
Secretary

(S E A L)

Davis, Chm., and Appling, C., concur;
Murray, C., concurs, with separate concurring
opinion attached;
Gaw and Clayton, CC., dissent, with separate
dissenting opinion(s) to follow;
and certify compliance with Section 536.080,
560 R 2000."

Dated at Jefferson City, Missouri,
on this 22nd day of February, 2007.

**THE NATIONAL ASSOCIATION OF
STATE UTILITY CONSUMER ADVOCATES
RESOLUTION 2007-01**

NASUCA ENERGY CONSERVATION AND DECOUPLING RESOLUTION

Whereas, the provision and promotion of energy efficiency measures are increasingly viewed by state commissions as a necessary component of utility service;

Whereas, many states are now encouraging rate-regulated utilities to adopt energy efficiency programs and other demand-side measures to decrease the number of units of energy each utility's customers purchase from the utility;

Whereas NASUCA has long supported the adoption of effective energy efficiency programs;

Whereas recent proposals by rate-regulated public utilities for the initiation or expansion of energy efficiency measures have featured utility rate incentives or revenue "decoupling" mechanisms that guarantee utilities a predetermined amount of revenues regardless of the number of units of energy sold;

Whereas, the utilities proposing decoupling measures seek guarantees from public utilities commissions that they will receive their allowed level of revenues;

Whereas, these utilities justify this departure from traditional rate-making principles on the theory they are being asked to help their customers purchase fewer energy units from them by promoting energy efficiency measures and other demand-side measures, thereby reducing their revenues and, consequently, their returns to their shareholders, and that decoupling mechanisms compensate utilities for revenues lost due to conservation;

Whereas, these utilities contend that because these measures reduce their revenues, they have a disincentive to encourage programs that aid their customers in purchasing fewer units of energy;

Whereas, historically, rates have been set in periodic rate cases by matching test-year revenues with test-year expenses, adding pro forma adjustments and allowing the utilities an opportunity to earn a reasonable rate of return on their investments in exchange for a state-protected monopoly;

Whereas revenue guarantee mechanisms allow rate adjustments to occur based upon one element that affects a utility's revenue requirement, without supervision or review of other factors that may offset the need for such a rate change;

Whereas, historically, rate-regulated utilities were not guaranteed they would earn the allowed return; rather, earnings depended on capable management operating the utilities in an efficient manner;

Whereas, many utilities proposing revenue decoupling request compensation for revenue lost per customer, implying that sales volumes are declining, when in fact these utilities' total energy sales revenues are stable or increasing;

Whereas, there are a number of factors that may cause a utility to sell fewer units of energy over a period of time, including weather, changing economic conditions, shifts in population, loss of large customers and switches to other types of energy, as well as energy efficiency and other demand-side measures;

Whereas many utilities have been offering cost-effective energy efficiency programs and actively marketing these programs for years without proposing or implementing rate incentives or revenue guarantee mechanisms such as decoupling, and have continued to enjoy financial health;

Whereas past experience has shown that revenue guarantee mechanisms such as decoupling may result in significant rate increases to customers;

Whereas some utilities have referenced the benefit of encouraging energy efficiency programs as a justification for revenue guarantee mechanisms without in fact offering any energy efficiency programs, indicating that the revenue guarantee mechanisms are attractive to utilities for reasons other than their interest in promoting energy conservation;

Whereas past experience has shown that rate increases prompted by revenue guarantee mechanisms such as decoupling are often driven not so much by reduced consumption caused by utility energy efficiency programs, as by reduced consumption due to normal business risks such as changes in weather, price sensitivity, or changes in the state of the economy;

Whereas utilities are better situated than are consumers or state regulators to anticipate, plan for, and respond to changes in revenue prompted by normal business risks, and the shifting of normal business risks away from utilities insulates them from business changes and reduces their incentive to operate efficiently and effectively;

Whereas the traditional ratemaking process has historically compensated utilities for experiencing revenue variations associated with normal business risks;

NOW THEREFORE NASUCA RESOLVES:

To continue its long tradition of support for the adoption of effective energy efficiency programs;

And to oppose decoupling mechanisms that would guarantee utilities the recovery of a predetermined level of revenue without regard to the number of energy units sold and the cause of lost revenue between rate cases;

BE IT FURTHER RESOLVED:

NASUCA urges Public Utilities Commissions to disallow revenue true-ups between rate cases that violate the matching principle, the prohibition against retroactive ratemaking, the prohibition against single-issue ratemaking, or that diminish the incentives to control costs that would otherwise apply between rate cases;

NASUCA urges State legislatures and Public Utilities Commissions to, prior to using decoupling as a means to blunt utility opposition to energy efficiency and other demand-side measures, (1) consider alternative measures that more efficiently promote energy efficiency and other demand side measures; (2) evaluate whether a utility proposing the adoption of a revenue decoupling mechanism has demonstrated a commitment to energy efficiency programs in the recent past; and (3) examine whether a utility proposing the adoption of a revenue decoupling mechanism has a history of prudently and reasonably utilizing alternative ratemaking tools;

If decoupling is allowed by any state commission, NASUCA recommends that the mechanism be structured to (1) prevent over-earning and provide a significant downward adjustment to the utilities' ROE in recognition of the significant reduction in risk associated with the use of a decoupling mechanism, (2) ensure the utility engages in incremental conservation efforts, such as including conservation targets and reduced or withheld recovery should the utility fail to meet those targets, and (3) require utilities to demonstrate that the reduced usage reflected in monthly revenue decoupling adjustments are specifically linked to the utility's promotion of energy efficiency programs.

NASUCA authorizes its Standing Committees to develop specific positions and to take appropriate actions consistent with the terms of this resolution to secure its implementation, with the approval of the Executive Committee of NASUCA. The Standing Committees or the Executive Committee shall notify the membership of any action taken pursuant to this resolution.

Approved by NASUCA:
Denver, Colorado

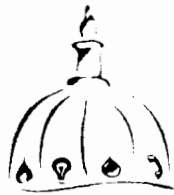
June 12, 2007

Opposed:
Ohio
Indiana
Colorado
Wyoming

Submitted by:
NASUCA Consumer Protection Committee

June 11, 2007

Abstained:
Massachusetts
California



NATIONAL ASSOCIATION
OF STATE UTILITY
CONSUMER ADVOCATES

NASUCA

Charles A. Acquard
EXECUTIVE DIRECTOR

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August 18, 2006

The Honorable Diane Munns
Board Member, Iowa Utilities Board,
President, NARUC
350 Maple Street
Des Moines, IA 50319-0069

Mr. James E. Rogers
President and Chief Executive Officer
Duke Energy Corporation
526 South Church Street
Charlotte, NC 28202

RE: National Action Plan for Energy Efficiency:

Dear Ms. Munns and Mr. Rogers:

The National Association of State Utility Consumer Advocates (NASUCA) has been asked to endorse the July 2006 National Action Plan for Energy Efficiency (Plan) you co-chaired. As president of NASUCA, I have been asked to respond to that request. The short answer is that there are differing opinions among our members on the issue of decoupling. Therefore, NASUCA is unable to arrive at the requisite consensus to give its unqualified support to the Plan.

The longer answer is that NASUCA's members uniformly support cost-effective energy efficiency measures and have long sought the Department of Energy's lead in developing such measures at the national level. In fact, in 1990 at its Santa Fe summer meeting, NASUCA adopted the following Resolution: *Urging the Department of Energy to Emphasize True Energy Efficiency in Formulating a National Energy Strategy*. Copy attached.

Ms. Diane Munns
Mr. James E. Rogers
August 18, 2006
Page 2

Furthermore, we feel that the Plan does have solid ideas and recommendations to further the goals of cost-effective energy efficiency. Our organization recognizes that cost-effective energy efficiency measures can help lower energy bills for our consumers and most of us have been supporters of those measures in our states.¹

That said, it is the opinion of many of our members that the Plan clearly promotes decoupling as a necessary, or at least a preferred, factor to accomplish effective energy efficiency. After discussion with the NASUCA membership there is a clear preference that decisions about whether to support decoupling revenues from sales be made by individual NASUCA members at the state level and not addressed in a national plan. For this reason, NASUCA is unable to endorse the Plan with our unqualified support.

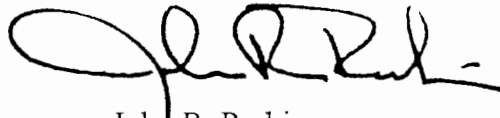
We want to assure you and the other committee members of our association's unwavering support for cost-effective energy efficiency as a necessary component of our nation's overall energy plan. The attached Resolution attests to that commitment. The fact NASUCA is unable to give its unqualified support to this Plan should in no way be

¹ For that reason, we were very disappointed to see the following comment in the Plan and feel it unfairly denigrates our members: "Higher rates are usually opposed by consumer advocates, even if the increase is for cost-effective energy efficiency or other investments." Plan at pp. 2-9. Nothing could be farther from the truth. Consumer advocates often settle rate cases with utilities which result in higher rates when convinced the utilities' needs for higher rates are justified. Furthermore, I am not aware of any consumer advocate who opposes cost-effective energy efficiency measures. We may disagree with the utility on what is cost-effective, but to state, in effect, that consumer advocates oppose energy efficiency as a knee-jerk reaction without careful analysis, is simply untrue.

Ms. Diane Munns
Mr. James E. Rogers
August 18, 2006
Page 3

viewed as a diminution of that long-term, long-time commitment.

Sincerely yours,

A handwritten signature in black ink, appearing to read 'John R. Perkins', with a stylized, cursive script.

John R. Perkins
Consumer Advocate of Iowa
NASUCA President

Enclosure

cc via email: Stacy Angel, U.S. Environmental Protection Agency Office of Air and
Radiation Climate Protection Partnerships Division,
E-mail: angel.stacy@epa.gov

Larry Mansueti U.S. Department of Energy Office of Electricity
Delivery and Energy Reliability E-mail: lawrence.mansueti@hq.doe.gov

NATIONAL ASSOCIATION OF STATE UTILITY CONSUMER ADVOCATES

RESOLUTION

Urging the Department of Energy To Emphasize True
Energy Efficiency in Formulating a National Energy Strategy

- WHEREAS, The United States Department of Energy (DOE) is in the process of formulating a National Energy Strategy [in late 1990] to guide national energy policy in the next 40 years;
- WHEREAS, DOE has issued an interim report describing and summarizing the comments presented to DOE in 15 public hearings during 1989 and early 1990;
- WHEREAS, the interim report includes goals for national energy strategy regarding natural gas, with policy options and obstacles identified by hearing participants;
- WHEREAS, the interim report reflects goals and concerns of energy producers, sellers and users, including consumers represented by members of the National Association of State Utility Consumer Advocates (NASUCA);
- WHEREAS, the comments and recommendations regarding natural gas presented in the interim report center on increasing production and usage of natural gas in various markets, with special emphasis on gas-fired electricity generation;
- WHEREAS, heavy emphasis throughout the interim report, including the introductory texts, is on the action of market forces in achieving national energy goals;
- WHEREAS, regulation of natural gas and electric utilities is intended to substitute for competition in the many circumstances in which the action of market forces favors energy producers and end-users with the greatest market power;
- WHEREAS, market forces may lead to beneficial results, including least cost choices, where actual competition exists and consumers have ready access to meaningful options, but regulatory oversight is appropriate where utilities can and do exercise monopoly power;

WHEREAS, unfettered market forces may lead to uneconomic energy uses and short-term investment choices unless government policy also requires conservation and least cost planning;

WHEREAS, the consumers represented by NASUCA are those with the least market power, whom regulation was intended to protect from abuses of monopoly power;

WHEREAS, the goal of enhanced energy efficiency which results in reduced energy usage and reduced energy costs must be carefully distinguished from the usage of the term "efficiency" when employed to promote the maximum usage of energy and transmission facilities on a sustained basis and to shift costs to captive consumers whose need for energy occurs primarily at peak periods;

WHEREAS, NASUCA supports utilization of demand-side measures which both encourage true energy efficiency and enable reduced peak usage of energy by both natural gas and electricity consumers;

THEREFORE, BE IT RESOLVED, that NASUCA urges the DOE in formulating the National Energy Strategy:

- to recognize explicitly that market forces alone cannot effectively implement a national energy strategy in the public interest;
- to incorporate an integrated least cost planning approach to address long-term energy needs, recognizing that market forces may distort choices by producers and consumers;
- to continue its emphasis on enhanced true energy efficiency, including demand side planning;
- to avoid reliance on market mechanisms which would negate the regulatory goals of protecting captive consumers who lack market power;
- to avoid policies in natural gas regulation, including rate design, which use the term "efficiency" to promote uneconomic uses and increased consumption of natural gas which merely serve to increase revenues of producers and pipelines;

- to enable a range of options to encourage consumers to conserve energy and to use it efficiently without unjustifiably shifting costs to peak users who have neither options nor market power.

BE IT FURTHER RESOLVED that NASUCA urges the Department of Energy to issue an initial draft of the final National Energy Strategy document for public comment prior to submission to the President of the United States.

BE IT FURTHER RESOLVED that the NASUCA Advocates authorize its Executive Committee to develop specific positions consistent with the terms of the Resolution on legislation, regulations or any other type of proposal that concerns the subject matter of this Resolution, including the development of any policy papers reflecting NASUCA's position. The Executive Committee shall advise the membership of any proposed action prior to taking such action, if possible. In any event, the Executive Committee shall notify the membership of any action under this provision.

BE IT FURTHER RESOLVED that NASUCA directs that copies of this resolution be sent to the Secretary of Energy, to Deputy Under Secretary of Energy in charge of developing the National Energy Strategy and to members of the Secretary of Energy Advisory Board.

Approved by NASUCA:

Santa Fe, New Mexico
PLACE

June 15, 1990
DATE

Submitted and Favorably
Reported by:

NASUCA Gas Committee

May 30, 1990
Date

COMMITTEE MEMBERS:

Margaret Ann Samuels (OH),
Chairman
Paul Buckley (MD)
Craig Burgraff (PA)
Rafael Epstein (NY)
Byron Harris (WV)
Joseph Ingles (UT)
Bill Kowalski (CN)
Sandra Mattavous-Frye (DC)
Carl McIntosh (SC)
Irwin Popowsky (PA)

NASUCA Electric Committee

COMMITTEE MEMBERS:

Irwin Popowsky (PA) Chairman
Steve Fogel (IL)
Larry Frimerman (OH)
Al Grandys (IL)
Billy Jack Gregg (WV)
Leland Hogan (UT)
Ray Lark (SC)
Paul Novak (MI)
Ed Petrini (VA)
Bill Riggins (KS)
Fred Schmidt (NV)
Charles Tutto (HI)

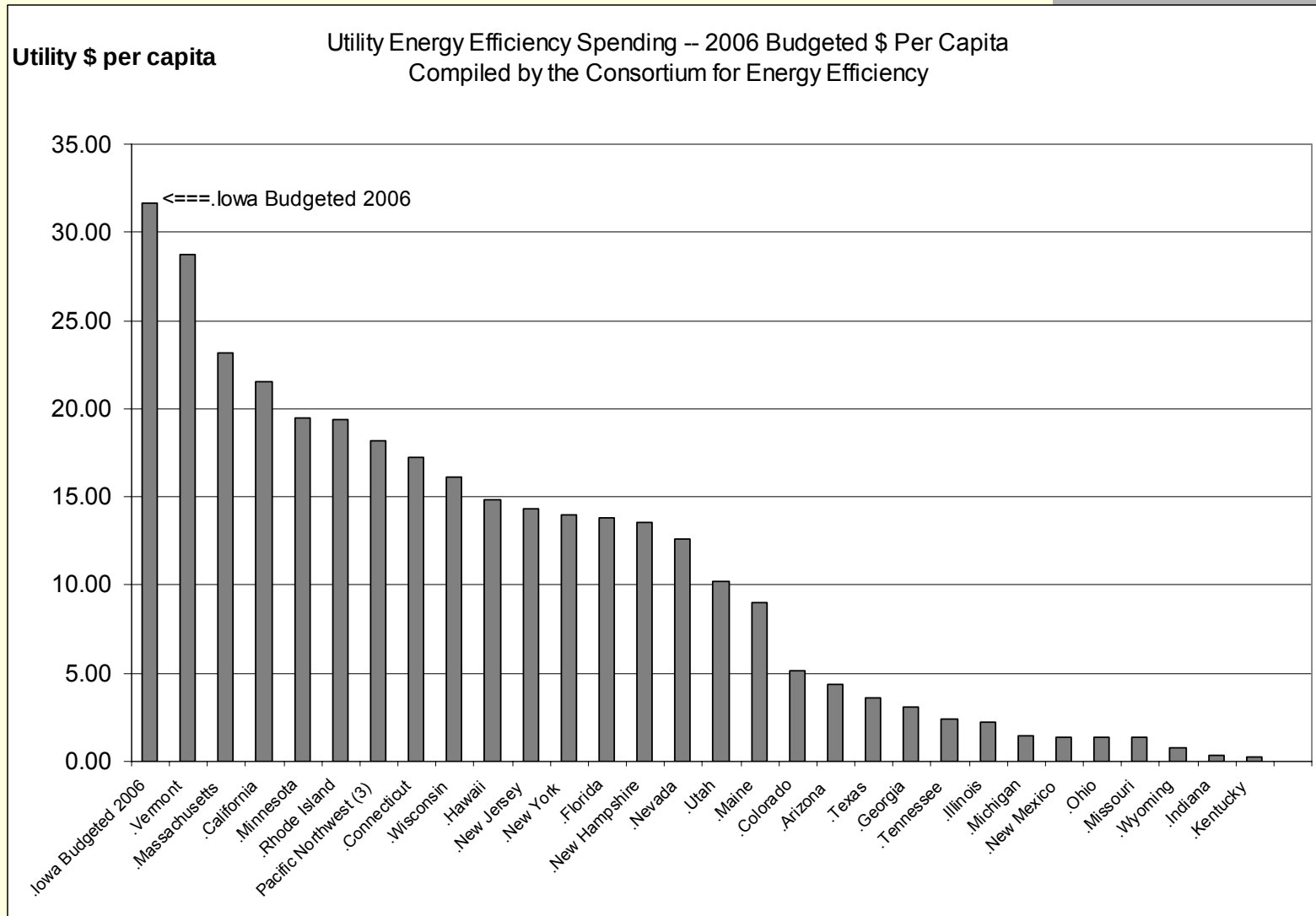
Policy Options for Energy Efficiency Programs: Decoupling, Incentives & Third-Party Administrators

NARUC SUMMER MEETING
New York City

July 17, 2007

John R. Perkins
Iowa Consumer Advocate

State Per Capita Energy Efficiency Expenditures



Iowa IOU Energy Efficiency Requirements

Iowa Code § 476.6(18)

- Spending targets eliminated; budgets are guided by IOU assessments of energy and capacity savings potential
- Utilities recover costs through energy efficiency cost recovery factor, which is reconciled annually with actual costs.
- IUB is authorized to conduct prudence reviews of utility energy efficiency plan implementation, with authority to disallow imprudent costs.
- No explicit authority for rewards or returns to IOUs.

2005 Demand-Side Management Results for Iowa Investor-Owned Utilities

Cumulative effects of 15+ years of IOU DSM:

- 1,600 GWh – about 5% of retail MWh sold in 2005
- 7,000,000 MCF – about 6.6% of retail sales in 2005
- Benefit/cost ratios averaged about 2.0 and NEW net societal benefits about \$100 million per year, over the period of 1999-2004
- IOU 2005 revenue averaged about \$0.066 per kWh and about \$11.65 per MCF
- IOU customers saved about \$106,000,000 in retail electric and \$81,000,000 in retail gas costs in 2005

Iowa Utilities Board Inquiry into the Effect of Reduced Usage on Rate-Regulated Natural Gas Utilities, Docket No. NOI-06-1

Question:

Are alternative regulation mechanisms (decoupling and rate design) needed to address impacts of reduced natural gas usage?

Iowa Utilities Board Inquiry into the Effect of Reduced Usage on Rate-Regulated Natural Gas Utilities, Docket No. NOI-06-1 -- Continued

Answer:

- Tension between energy efficiency & natural gas utilities' opportunity to earn authorized rate of return “does not appear to be a substantial problem in Iowa.”
- The data does not show a direct correlation between IOU net operating income and declining customer usage as a result of energy efficiency programs.

Many factors contribute to decline in use per customer

- Price elasticity
- Non-company sponsored conservation
 - Nonprofit Associations (MEEA, NWEEA, ACEEE)
 - State Energy Offices EE Research Facilities
- Federal appliance efficiency standards
- Turnover of housing stock
- More efficient building codes
- Economic conditions
- Milder winters
- Company-sponsored energy efficiency

Reason 1 for Rejecting Decoupling

- Significant departure from proven regulation.
 - Base rates are typically fixed and based upon an allowed rate of return under traditional regulation.
 - Parties are forced to acknowledge both favorable and unfavorable changes at date X — not piecemeal
 - Financial need must be proven, nothing is automatic
 - Parties have formal process for discovery, analysis and issue development

Reason 1 for Rejecting Decoupling

(Continued)

- Between rate cases:
 - actual rates of return can vary from allowed.
 - regulatory lag can provide important incentives.
 - it is up to the utility to manage risk associated with sales (revenue) and find opportunities for efficiency (cost). Use of hedging increasing.
 - decoupling substantially reduces or eliminates the need to manage sales risk.

Reason 2 for Rejecting Decoupling

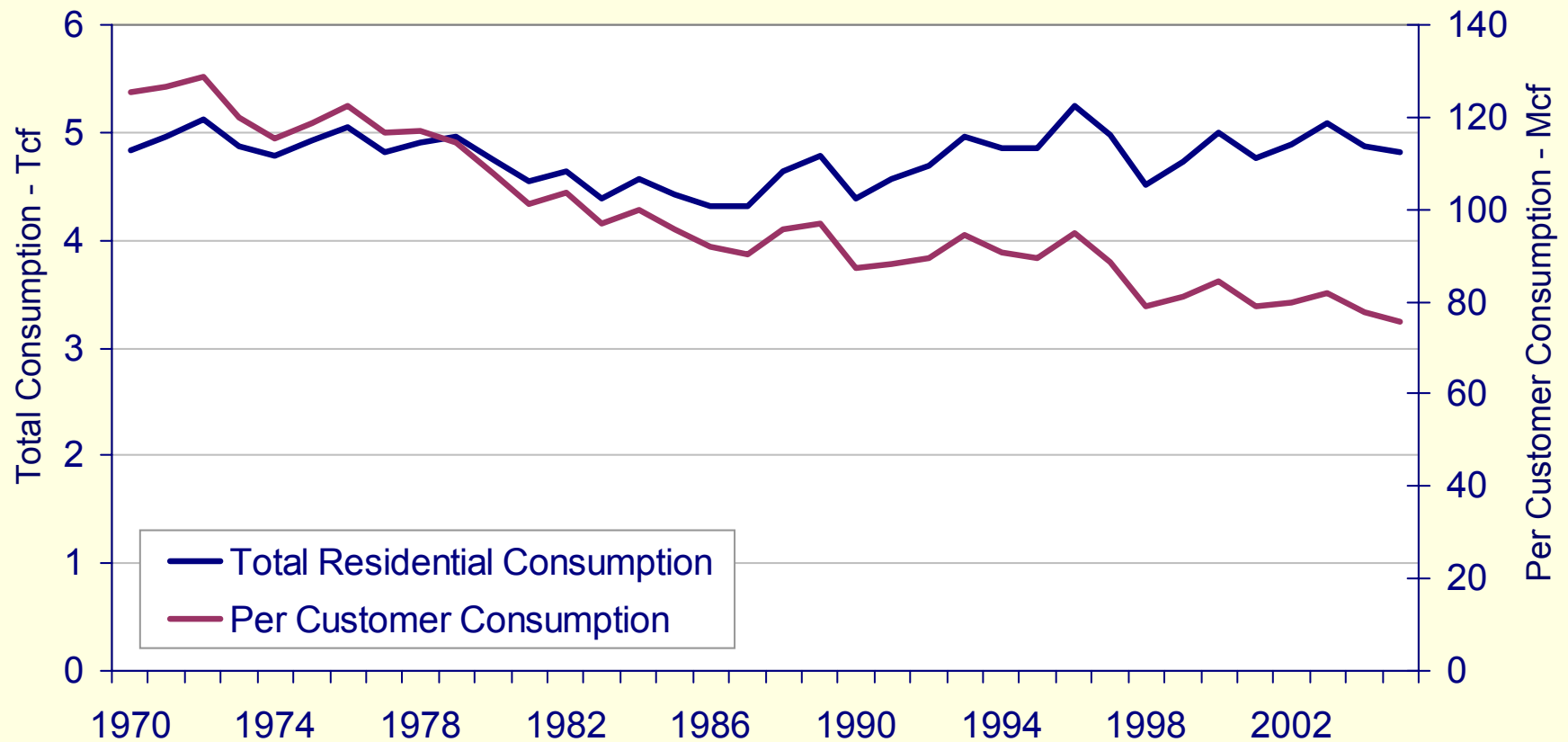
- Shifts sales risks from utilities to customers.
 - Economy
 - Weather
 - Commodity Prices
 - Other Unanticipated Factors

Reason 3 for Rejecting Decoupling

- The impact of changes in use per customer for the gas industry are overstated and address the wrong causes on changes in margins.

Reason 3 for Rejecting Decoupling (Continued)

While overall use per customer is decreasing, overall residential natural gas usage is flat to increasing.



Reason 3 for Rejecting Decoupling (Continued)

<u>Decrease in Average Annual Per Customer Weather Normalized Gas Usage 1990 – 2005</u>		<u>Res. Customer Count (avg) % chg 1990-05</u>
•MidAmerican Residential	-35.18%	20.62%
•IPL Residential	-22.90%	15.24%
•Aquila Residential	-27.22%	21.13%
Weighted Average	-28.80%	19.34%

Reason 4 for Rejecting Decoupling

- At best, the incentive issue is not resolved and never can be with revenue decoupling.
- At worst, discourages customers from energy conservation efforts.
- Don't discount value of utility's good-will incentive to get into customers' homes to present EE ideas, devices and rebates.

3rd Party Administrators

Example: Efficiency Vermont, Energy Trust of Oregon

Pros:

- Removes utilities “disincentive” to promote EE programs.
- Uniform statewide programs.
- Expertise in EE resides in one agency—not fragmented among utilities.
- Promotes most cost-effective programs—financial viability depends on success.
- Reduces controversy over programs adopted.

3rd Party Administrators

**Example: Efficiency Vermont, Energy Trust of Oregon
(Continued)**

Cons:

- System benefits fund could be subject to legislative raid.
- Tension between utilities and 3rd party administrator over access to billing data.
- PUC oversight still required.
- Utilities good-will opportunity lost.

THE NATIONAL ASSOCIATION OF STATE UTILITY CONSUMER ADVOCATES

Resolution 2007-01

NASUCA ENERGY CONSERVATION AND DECOUPLING RESOLUTION

Whereas, the provision and promotion of energy efficiency measures are increasingly viewed by state commissions as a necessary component of utility service;

Whereas, many states are now encouraging rate-regulated utilities to adopt energy efficiency programs and other demand-side measures to decrease the number of units of energy each utility's customers purchase from the utility;

Whereas NASUCA has long supported the adoption of effective energy efficiency programs;

Whereas recent proposals by rate-regulated public utilities for the initiation or expansion of energy efficiency measures have featured utility rate incentives or revenue "decoupling" mechanisms that guarantee utilities a predetermined amount of revenues regardless of the number of units of energy sold;

Whereas, the utilities proposing decoupling measures seek guarantees from public utilities commissions that they will receive their allowed level of revenues;

Whereas, these utilities justify this departure from traditional rate-making principles on the theory they are being asked to help their customers purchase fewer energy units from them by promoting energy efficiency measures and other demand-side measures, thereby reducing their revenues and, consequently, their returns to their shareholders, and that decoupling mechanisms compensate utilities for revenues lost due to conservation;

Whereas, these utilities contend that because these measures reduce their revenues, they have a disincentive to encourage programs that aid their customers in purchasing fewer units of energy;

Whereas, historically, rates have been set in periodic rate cases by matching test-year revenues with test-year expenses, adding pro forma adjustments and allowing the utilities an opportunity to earn a reasonable rate of return on their investments in exchange for a state-protected monopoly;

Whereas revenue guarantee mechanisms allow rate adjustments to occur based upon one element that affects a utility's revenue requirement, without supervision or review of other factors that may offset the need for such a rate change;

Whereas, historically, rate-regulated utilities were not guaranteed they would earn the allowed return; rather, earnings depended on capable management operating the utilities in an efficient manner;

Whereas, many utilities proposing revenue decoupling request compensation for revenue lost per customer, implying that sales volumes are declining, when in fact these utilities' total energy sales revenues are stable or increasing;

Whereas, there are a number of factors that may cause a utility to sell fewer units of energy over a period of time, including weather, changing economic conditions, shifts in population, loss of large customers and switches to other types of energy, as well as energy efficiency and other demand-side measures;

Whereas many utilities have been offering cost-effective energy efficiency programs and actively marketing these programs for years without proposing or implementing rate incentives or revenue guarantee mechanisms such as decoupling, and have continued to enjoy financial health;

Whereas past experience has shown that revenue guarantee mechanisms such as decoupling may result in significant rate increases to customers;

Whereas some utilities have referenced the benefit of encouraging energy efficiency programs as a justification for revenue guarantee mechanisms without in fact offering any energy efficiency programs, indicating that the revenue guarantee mechanisms are attractive to utilities for reasons other than their interest in promoting energy conservation;

Whereas past experience has shown that rate increases prompted by revenue guarantee mechanisms such as decoupling are often driven not so much by reduced consumption caused by utility energy efficiency programs, as by reduced consumption due to normal business risks such as changes in weather, price sensitivity, or changes in the state of the economy;

Whereas utilities are better situated than are consumers or state regulators to anticipate, plan for, and respond to changes in revenue prompted by normal business risks, and the shifting of normal business risks away from utilities insulates them from business changes and reduces their incentive to operate efficiently and effectively;

Whereas the traditional ratemaking process has historically compensated utilities for experiencing revenue variations associated with normal business risks;

NOW THEREFORE NASUCA RESOLVES:

To continue its long tradition of support for the adoption of effective energy efficiency programs;

And to oppose decoupling mechanisms that would guarantee utilities the recovery of a predetermined level of revenue without regard to the number of energy units sold and the cause of lost revenue between rate cases;

BE IT FURTHER RESOLVED:

NASUCA urges Public Utilities Commissions to disallow revenue true-ups between rate cases that violate the matching principle, the prohibition against retroactive ratemaking, the prohibition against single-issue ratemaking, or that diminish the incentives to control costs that would otherwise apply between rate cases;

NASUCA urges State legislatures and Public Utilities Commissions to, prior to using decoupling as a means to blunt utility opposition to energy efficiency and other demand-side measures, (1) consider alternative measures that more efficiently promote energy efficiency and other demand side measures; (2) evaluate whether a utility proposing the adoption of a revenue decoupling mechanism has demonstrated a commitment to energy efficiency programs in the recent past; and (3) examine whether a utility proposing the adoption of a revenue decoupling mechanism has a history of prudently and reasonably utilizing alternative ratemaking tools;

If decoupling is allowed by any state commission, NASUCA recommends that the mechanism be structured to (1) prevent over-earning and provide a significant downward adjustment to the utilities' ROE in recognition of the significant reduction in risk associated with the use of a decoupling mechanism, (2) ensure the utility engages in incremental conservation efforts, such as including conservation targets and reduced or withheld recovery should the utility fail to meet those targets, and (3) require utilities to demonstrate that the reduced usage reflected in monthly revenue decoupling adjustments are specifically linked to the utility's promotion of energy efficiency programs.

NASUCA authorizes its Standing Committees to develop specific positions and to take appropriate actions consistent with the terms of this resolution to secure its implementation, with the approval of the Executive Committee of NASUCA. The Standing Committees or the Executive Committee shall notify the membership of any action taken pursuant to this resolution.

Approved by NASUCA:

Denver, Colorado

June 12, 2007

Submitted by:

NASUCA Consumer Protection Committee

June 11, 2007

Opposed:

Ohio

Indiana

Colorado

Wyoming

Abstained:

Massachusetts

California

Atmos/United Consolidated Capital Structure, And
Returns In TN

Atmos/United: Audited Consolidated Capitalization Per Annual SEC 10-K Filings (In Thousands of \$)											
Capital Structure Components As Of:	2004: Sep 30	2003: Sep 30	2002: Sep 30	2001: Sep 30	2000: Sep 30	1999: Sep 30	1998: Sep 30	1997: Sep 30	1996: Dec 31	1995: Dec 31	CAPD Expected 2005: Sep 30
Short-Term Debt: Notes Due	\$0	\$118,595	\$145,791	\$201,247	\$250,047	\$168,304	\$17,491	\$167,300	\$65,688	\$32,313	
Short-Term Debt: Current Portion of Long-Term Debt	\$5,908	\$9,345	\$21,980	\$20,695	\$17,566	\$17,848	\$57,783	\$15,201	\$7,679	\$9,155	
Long-Term Debt	\$861,311	\$863,918	\$670,463	\$692,399	\$350,567	\$362,675	\$377,380	\$297,303	\$153,859	\$163,160	
Common Equity	\$1,133,459	\$857,517	\$573,235	\$583,864	\$392,466	\$377,663	\$371,158	\$327,260	\$157,284	\$146,071	
Preferred	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	\$0	
Total	\$2,000,678	\$1,849,375	\$1,411,469	\$1,498,205	\$1,010,646	\$926,490	\$823,812	\$807,064	\$384,510	\$350,699	
RATIOS:											
A1 Short-Term Debt: Notes Due	0.0%	6.4%	10.3%	13.4%	24.7%	18.2%	2.1%	20.7%	17.1%	9.2%	0.0%
A2 Short-Term Debt: Current Portion of Long-Term Debt	0.3%	0.5%	1.6%	1.4%	1.7%	1.9%	7.0%	1.9%	2.0%	2.6%	0.0%
A3 Long-Term Debt	43.1%	46.7%	47.5%	46.2%	34.7%	39.1%	45.8%	36.8%	40.0%	46.5%	59.8%
A4 Common Equity	56.7%	46.4%	40.6%	39.0%	38.8%	40.8%	45.1%	40.5%	40.9%	41.7%	40.2%
A5 Preferred	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
A6 Total	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
Atmos/United: Equity Return In Tennessee 2004-1995											
	2004: Sep 30	2003: Sep 30	2002: Sep 30	2001: Sep 30	2000: Sep 30	1999: Sep 30	1998: Sep 30	1997: Sep 30	1996: Dec 31	1995: Dec 31	2005: Sep 30
OR Reported Overall Return In Tennessee - On Sep 30 Per TRA 303 Form	11.02%	9.04%	9.46%	10.29%	9.35%	7.42%	11.37%	9.17%	10.39%	9.19%	11.02%
B1 Interest Rate On Short Term Debt**	N/A	1.02%	1.73%	2.96%	6.49%	5.28%	5.44%	5.49%	5.95%	5.80%	N/A
B2 Calculated Short Term Debt Cost = Line B1 X A1	0.00%	0.07%	0.18%	0.40%	1.61%	0.96%	0.12%	1.14%	1.02%	0.53%	0.00%
B3 Interest Rate On Long Term Debt	6.82%	6.84%	7.65%	7.58%	8.07%	8.14%	8.01%	8.73%	8.97%	8.94%	6.82%
B4 Calculated Long Term Debt Cost = Line B3 X A3	2.96%	0.55%	1.03%	1.81%	3.97%	3.13%	2.99%	3.26%	3.52%	3.38%	4.08%
B5 Atmos's Equity Return In Tennessee = (Line OR - Line B2 - Line B3) / (Line A4) [Common Equity Ratio]	14.2%	18.2%	20.3%	20.7%	9.7%	8.2%	18.3%	11.8%	14.3%	12.7%	17.3%
**CAPD Estimate Based On Federal Reserve Board's Listing of Short Debt Costs For The Month Ending The Fiscal Year, September or December. Compare To The Prepared Testimony Of The Company's Witness. The cost of short-term debt that is appropriate for this proceeding is 8.5% Prepared Testimony Of Company Witness, Dr. Murry, Page 7, Line 10, May 15, 1995"											
											CAPD Expected 2005: Sep 30

Current Extension Policy

T.R.A. No. 1

1st Revised Sheet No. 62

Cancelling Original Sheet No. 62

ATMOS ENERGY CORPORATION

GENERAL RULES AND REGULATIONS (Continued)

- (b) In the event of stoppage or failure of any meter to register properly, Customer will be billed for such period on an estimated consumption based upon his use of gas in a similar period of like use or on the basis of check meter readings, if available and accurate, but such adjustment shall not be made for more than six months.
- (c) In the event of tampering or unauthorized use of Company's facilities, the probable gas consumption shall be estimated by Company and billed to Customer. If the duration of such tampering or unauthorized use is not known, it shall be conclusively presumed to be since the commencement of Customer's service but for a period of not more than six months.
- (d) All property of Company installed in or upon premises of, or occupied by Customer is under Customer's protection. All reasonable care shall be exercised by Customer to prevent loss of or damage to such property, ordinary wear and tear excepted. Customer will be liable for any loss of property or damage thereto and shall pay to Company the cost of appropriate repairs or replacements for such loss or damage to property.

7. Extension and Installation of Company Facilities

This Company will, upon written application, extend its gas mains to serve bona fide applicants of a permanent and established character in accordance with the provisions of this Service Regulation. Gas main extensions shall be made only along public streets, roads or highways and upon private property across which satisfactory rights of way or easements have been provided without cost to the Company. All gas mains constructed pursuant to this service regulations shall be owned, operated, and maintained by the Company.

7.1 Free Extension Allowance

Any extension from existing mains to the point of connection with Customer's service line, whether on public property or on private property, is considered to be an extension of a main. Any extension, from existing mains or from an extension of a main as defined above, to Customer's property for service to Customer shall be considered a part of the service line to service such Customer.

ATMOS ENERGY CORPORATION

GENERAL RULES AND REGULATIONS (Continued)

Gas mains will be extended by the Company to supply new Customers, without additional charge for any extension, provided the length of such extension does not exceed the length calculated using the following formula:

1. Residential Customers:

- a. Free length = one (1) foot per Mcf of estimated total annual gas consumption.

This free length formula is based upon extension of a 2 inch polyethylene main. If Customer(s)' load requires a larger and/or steel main, Customer(s) will be required to deposit the difference between the estimated cost of the main required to service Customer(s) and the estimated cost of the free extension calculated by this formula.

b. Commercial and Industrial Customers:

1. For each customer whose annual consumption is estimated by the Company to be 500 Mcf or less, the free length shall be computed in accordance with paragraph (a) of the section.
2. For each customer whose annual consumption is estimated by the Company to be over 500 Mcf, the free length, if any, will be determined on an individual feasibility basis considering the required investment, character, and economic life of the load, and other appropriate information.

c. General

1. No free length allowance will be made for usage for temporary, standby, auxiliary, or emergency use only.
2. The Company is under no obligation to provide a free length allowance under the optional rate schedules.

GENERAL RULES AND REGULATIONS (Continued)

7.2 Extensions Beyond the Free Limit - Residential and Commercial

1. Upon completion of a "Contract for Extension of Distribution Main Beyond Free Length", the Company will extend its mains to a Customer beyond the Free Length provided the Customer deposits a construction charge with the Company sufficient to cover the construction expense for service to the Customer in excess of the free length of 2 inch polyethylene main.
2. The Company has discretion to waive payment for excess cost over free allowance when, in Company's opinion, such payment would, within a reasonable period of time, be fully refundable. Exceptions to this rule may also be made by the Company when system improvements are realized by the extension or when the extension would enhance the opportunity of adding new customers in the future.
3. As additional Customers are served through a service line connected directly to the specifically involved main extension within five (5) years of its completion date, the original Customer(s) shall be refunded an amount determined as follows:
 - a. The contract with the original Customer(s) shall set forth the estimated cost per foot for a normal 2 inch polyethylene main extension.
 - b. The Company will estimate the annual gas consumption (Mcf) of each new Customer added to the main extension.
 - c. The refund shall be determined by the following formula:
$$\text{Refund} = \text{the estimated cost per foot from (a) times the estimated annual gas consumption (Mcf) for the new Customer.}$$
 - d. The refund to the original Customer(s) shall not exceed the amount of the original construction charge deposited with the Company.
 - e. No interest shall be paid on the construction charge deposit.
 - f. The refund(s) due, if any, to the original Customer(s) will be calculated and paid on June 1st of every year. Refunds will not be made any other time.

GENERAL RULES AND REGULATIONS (Continued)

- g. If the Company has allowed the Customer to pay the construction charge over a period of time in accordance with Section 7.2(4), all refunds attributable to the connecting of new Customers to the specifically involved main extension will be credited to any outstanding balance owed for the construction charge.
- 4. Individual residential customers may elect to spread the payment of the construction charge for footage beyond the Free Limit up to, but not to exceed, a three year period at no interest provided that the Customer shall enter into a "Contract for Extension of Distribution Main Beyond Free Length" and also subject to the following conditions:
 - a. The Company shall approve the Customer's credit prior to the signing of the "Contract for Extension of Distribution Main Beyond Free Length".
 - b. Default by the Customer under the terms of the "Contract for Extension of Distribution Main Beyond Free Length" may result in discontinuance of service as per the current provisions of Section 5 of these General Rules and Regulations.
 - c. If a Customer cancels service prior to payment of the total construction charge for footage beyond the Free Limit, the unpaid balance shall become due and payable immediately. The Company may use any deposit or credit owed to the Customer to offset the balance due under the "Contract for Extension of Distribution Main Beyond Free Length".
 - d. Refunds due the Customer under section 7.2 (3) shall be credited to the outstanding loan balance.
 - e. In no case will the Company build without cost to the applicant more service line than is necessary to reach the acceptable meter location by the most economical route, even though any additional line would still come within the free allowance.

ATMOS ENERGY CORPORATION

GENERAL RULES AND REGULATIONS (Continued)

5. In addition to all other of these Service Regulations the following shall also apply to Mobile Home Parks:
- a. For the purpose of these regulations, a Mobile Home Park is defined as any tract or parcel of land used primarily to provide sites for the parking and occupancy of Mobile Homes. A Mobile Home is defined as a portable structure built so as to be readily transportable from one location to another, and which is usable as a dwelling for one or more persons, herein referred to as Mobile Home Occupants. Any person, firm or corporation who operates a Mobile Home Park as a commercial venture shall be referred to as a Mobile Home Park Owner.
 - b. Any Mobile Home Park Owner desiring gas service within a Mobile Home Park shall enter into a contract with the Company for a minimum period of five (5) years for service from Company's distribution mains to a specified number of Mobile Home sites. Mobile Home Park Owner agrees to pay the Company each month, commencing with a date specified in the contract and each month thereafter for the term of the contract, an amount specified as the customer charge under the provisions of Company's Residential Rate Schedule 210, as filed with the Tennessee Regulatory Authority, for 70% of the number of specified Mobile Home sites less the number of sites occupied by Mobile Home Occupants who were customers of, and who were billed for gas service by, the Company during such month.
 - c. After execution of a contract for gas service to a Mobile Home Park, the Company will construct the required extension of distribution facilities to serve the number of sites specified in the contract provided that the total free length allowance for mains and services shall be calculated as per the provisions of Paragraph No. 7. For mains and services exceeding the free length allowance the Mobile Home Park Owner will be required to deposit a Refundable Advance as per the provisions of Paragraph No. 7.

New Proposal

ATMOS ENERGY CORPORATION

T.R.A. No. 1
2nd Revised Sheet No. 62
Cancelling 1st Sheet No. 62

GENERAL RULES AND REGULATIONS (Continued)

- (b) In the event of stoppage or failure of any meter to register properly, Customer will be billed for such period on an estimated consumption based upon his use of gas in a similar period of like use or on the basis of check meter readings, if available and accurate, but such adjustment shall not be made for more than six months.
- (c) In the event of tampering or unauthorized use of Company's facilities, the probable gas consumption shall be estimated by Company and billed to Customer. If the duration of such tampering or unauthorized use is not known, it shall be conclusively presumed to be since the commencement of Customer's service but for a period of not more than six months.
- (d) All property of Company installed in or upon premises of, or occupied by Customer is under Customer's protection. All reasonable care shall be exercised by Customer to prevent loss of or damage to such property, ordinary wear and tear excepted. Customer will be liable for any loss of property or damage thereto and shall pay to Company the cost of appropriate repairs or replacements for such loss or damage to property.

7. Extension and Installation of Company Facilities

This Company will, upon written application, extend its gas mains to serve bona fide applicants of a permanent and established character in accordance with the provisions of this Service Regulation. Gas main extensions shall be made only along public streets, roads or highways and upon private property across which satisfactory rights of way or easements have been provided without cost to the Company. All gas mains constructed pursuant to this service regulation shall be owned, operated, and maintained by the Company.

7.1 Main Extensions

Any extension from existing mains to the point of connection with Customer's service line, whether on public property or on private property, is considered to be an extension of a main. Any extension, from existing mains or from an extension of a main as defined above, to Customer's property for service to Customer shall be considered a part of the service line to service such Customer.

GENERAL RULES AND REGULATIONS (Continued)

Revenue for how long?

The Company will install all mains, service lines, metering, and regulating equipment necessary to serve the customer(s) free of charge, provided the revenue expected to be realized produces a rate of return on the investment that is equal to or greater than the minimum allowed rate of return on equity approved in the Company's most recent rate case. This rate of return analysis will be based on a feasibility study performed by the company. This study will include consideration of all costs needed to provide service (materials, company and/ or contract labor, overheads, and applicable taxes). These costs will be compared to the revenue that is either contracted for or can be reasonably expected to be generated by the customers served by the extension. Should this analysis result in a rate of return (ROE) less than the minimum allowed rate of return approved in the Company's most recent rate case, then the customer(s) may be required to remit to the company an Aid-in-Construction (AIC), including any applicable taxes, to make up the difference in the actual and allowable rate of return.

how long?

General

1. The Company may, at its sole discretion, choose to waive payment for AIC when system improvements are realized by the extension or when the extension would enhance the opportunity of adding new customers in the future.
2. Individual customers may elect to spread the payment of any required AIC up to, but not to exceed, a three year period at no interest provided that the Customer shall enter into a "Main Extension Contract" and also subject to the following conditions:
 - a. The Company shall approve the Customer's credit prior to the signing of the "Main Extension Contract".
 - b. Default by the Customer under the terms of the "Main Extension Contract" may result in discontinuance of service as per the current provisions of Section 5 of these General Rules and Regulations.
 - c. If a Customer cancels service prior to payment of the total AIC required, the unpaid balance shall become due and payable immediately. The Company may use any deposit or credit owed to the Customer to offset the balance due under the "Main Extension Contract".
 - d. In no case will the Company build without cost to the applicant more service line than is necessary to reach the acceptable meter location by the most economical route.

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Sunday, 07/29/07

Sun Belt growth pressures Nashville

Newcomers bring wealth, challenges

By CHAS SISK
Staff Writer

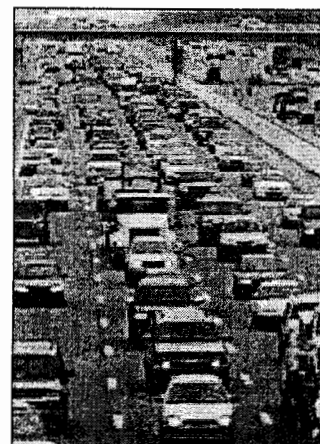
Sean Rauch had never been to Tennessee, never been to the South, never been east of the Rocky Mountains until this summer. But that didn't deter the 36-year-old park supervisor and his wife from pulling up their roots in San Diego, Rauch's home since birth.

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Twisted ankle?
Ask a doctor.

Armed late last month with listings culled online, Sean and Maggie Rauch traveled for the first time to Nashville — a city in which they had no jobs, no relatives and no acquaintances other than a real estate agent — for a rushed tour of 22 homes.

Four days later, they signed a contract on a 2,400-square-foot house in Hendersonville, a city they knew only as the place where Johnny and June Carter Cash's home

[enlarge](#)[enlarge](#)

burned down this spring.

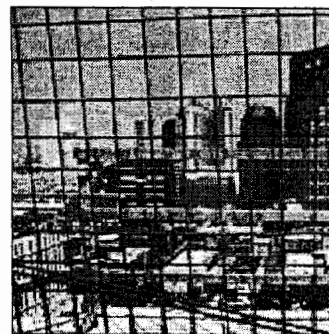
Twice as big yet half the price of their California home, the Rauches' new house is meant to help them escape San Diego's high cost of living.

People like the Rauches are propelling growth in Middle Tennessee. Refugees from other parts of the Sun Belt, eager to escape the congestion, pollution, rising costs and frenetic pace of sprawling boomtowns, are leading a surge of people that is redefining the region.

Nearly half a million people, a large portion of them from the sprawling metropolises of the Southeast and the Southwest, have come to the Midstate since 1990.

But as growth accelerates, Nashville and its suburbs are also being faced with the issues that other Southern cities have fumbled: sprawl, immigration, crime, pollution and a widening gap between rich and poor.

How the city handles those questions will determine whether Nashville pulls itself into the top ranks of American cities or falls back into the second tier, and whether Nashville can preserve its special character even as it is reshaped by newcomers who bring their own values and cultures with them.



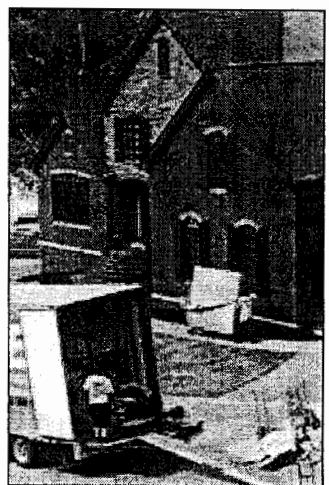
[enlarge](#)

Jeno Harmon installs rebar on the building on Third Avenue South. The 1990s helped fuel other growth in the city. (MCCORMACK / THE TENNESSEAN)



[enlarge](#)

Gabriel and Ilcencia Hernandez, middle, and Ruby, right, at their home. Despite their roots and extended family in the state, they left because of runaway growth in the state. (SANFORD MYERS / THE TENNESSEAN)



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I wish more people from the Northeast and West Coast would move here. Arts, sports, Cultrue and Fine Dining have never been better in Music City. Many people that I meet when I travel don't roll there eyes anymore when I tell them where I'm from!

Posted: Sun Jul 29, 2007 11:54 pm

Lance Boyle

You are truly a legend in your own mind.

Posted: Sun Jul 29, 2007 8:22 pm

Gatorgabe: You demonstrate a cetain parochialism: First in asserting that "Native Americans" live on reservations. Aside from the fact that anyone born on a res has the freedom to move if they so desire, there are many nations, what you Yankees call tribes, that don't live on reservations or in pueblos, including the Five Civilized Tribes that were removed from the Southeast and resettled in what is now Oklahoma and adjoining states (leaving behind a number of persons who mostly assimilated with the settlers. The Southern Band Seminoles with whom you may be familiar from your Florida experience are a special case. The western band Seminoles do not live on reservations.

Second, you fail to understand, indeed probably were never taught, that the South had a different history and experience with immigration than the Northern and midwestern states. During the War of Northern Agression, The South was ravaged by the Yankee Army, which included many new immigrants from Europe, under the command of war criminals like Lincoln, Grant and Sherman, which deliberately violated the laws of war by targeting the civilian population.

As a result of The War and the Occupation, the South just wasn't an attractive place for new immigrants in the two great waves of immigrants from central and southern Europe which occurred in the latter 19th and early 20th century, and not even a lot of post-WWII refugees settled in the South, preferring established communities of immigrants from their homeland. While the South was split along racial lines until the 1970s, the South was the last place in the United States where the majority of whites were descended from British ancestors. In rural and small town Tennessee, it was not unusual for most of the white population to be descended from orignal pioneers and settlers. And obviously, the African-American population was descended from ancestors who arrived prior to the end of slave importation (which predated The War).

While there were some German and Italians and other Europeans who made their way here, most chose not to. And the South had already had a less than pleasant experience with land-grabbing and other forms of coercive commerce by carpetbaggers (including many recent immigrants)from up North during the Occupation, which they called Reconstruction.

So the "We're all immigrants" line just doesn't play well with most of us who are truly "from here". In the local vernacular, being "from here" doesn't mean residing here, or even necessarily being born here: It implies that your family and ancestors were born here as well.

Telling someone whose family pioneered and settled Tennessee seven and eight generations ago, most of whom came from families that had already been in the original colonies for generations before that, often intermarrying with indigenous people, that they are just another immigrant is not going to be taken well. You might as well get used to that fact, and be prepared to accept the consequences if you insist upon repeating it. Southern nationalism may be in the minority, but its far from dead nor is it limited to the "inbred" and/or uneducated.

Posted: Sun Jul 29, 2007 6:07 pm

bet Charlie Daniels could write a tune on her view
he is a simple man is a good tune to start with

Posted: Sun Jul 29, 2007 5:44 pm

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[enlarge](#)

Minister Larry Tomczak, who moved from Atlanta, greets worshipper Outreach Center service at the F Nashville has a fresh openness t MYERS / THE TENNESSEAN)



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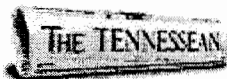
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Thursday, 06/28/07

Midstate cities just keep getting bigger

Boomtowns surround Nashville

By JENNIFER BROOKS
Staff Writer

The Nashville metropolitan area is home to eight of the 10 fastest growing towns in Tennessee, according to census estimates to be released today.

Murfreesboro is growing at a rate of 5,000 residents a year. Nashville's population grew by more than 3,000 in 2006. Spring Hill is neck and neck with a small Memphis suburb for the title of fastest-growing city in the state. La Vergne, Franklin, Brentwood, Mt. Juliet and Hendersonville rounded out the list of cities that gained the most new residents over the past five years.

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As their populations boom, cities are scrambling to build enough roads, schools, sewer lines and services to

accommodate them. Meanwhile, Middle Tennesseans are getting used to the realities of suburban sprawl — traffic jams, nonstop construction and unfamiliar faces.

"It used to be, you could go into Shoney's at night and you knew everybody there. Now, you don't recognize any of the faces," said Matthew Royal, who moved to Murfreesboro in 1956 and spent the next 50 years watching the town grow by leaps and bounds. The latest census estimate shows the city population pushing 92,000.

"People go where the jobs are," said William Canak, professor of sociology at Middle Tennessee State University in Murfreesboro, noting that many of the fastest growing communities are in Rutherford County, one of the fastest growing labor markets in the state. "You have a very active business market, a tight labor market — people are coming here."

Spring Hill 39th in nation

Spring Hill is the 39th-fastest growing community in the nation, according to the 2006 U.S. Census Bureau population estimates. An additional 3,625 people packed into Saturn's hometown, pushing the official federal population estimate from 17,143 in 2005 to 20,768 — a staggering increase for a town that had just 7,000 residents six years ago.

"Spring Hill is becoming a destination city," said Spring Hill Mayor Danny Leverette, who takes considerable pride in his town's population boom and the new jobs, new development and bigger cut of state revenue sharing it has brought to his town. In fact, Spring Hill's own estimate puts the town's population closer to 23,462.



Construction crews work at the future site of a Mimis Cafe at a shopping center in a burgeoning retail area of Murfreesboro. (DIPTI VAIDYA / THE TENNESSEAN)



Matthew Royal has lunch in the City Cafe in Murfreesboro. Murfreesboro is growing at a rate of about 5,000 newcomers a year, according to census figures to be released today. (DIPTI VAIDYA / THE TENNESSEAN)



Josh Shelton, left, and Don Pickett install a picket fence at the home of Brandi and Kevin Conklin in Spring Hill, Tenn., on Wednesday, June 27, 2007. The Conklins moved to Spring Hill from Franklin for the more affordable cost of living and to be near other young families. (SHAUNA BITTLE / THE TENNESSEAN)

RELATED MEDIA

■ Graphic: Magnet cities in Tennessee

"We have to try to stay out in front of the growth," said Leverette, who expects Spring Hill to eventually reach a population of 50,000. "We're planning now so we can be the best we can be."

Suburbs grow fastest

Nationwide, the census data show that suburbs, not cities, are the fastest growing communities. Every city on the list of the 10 fastest growing communities in the nation — measured by percentage of growth — is a suburb.

Much of the suburban growth has come at the expense of the urban core. Detroit, Chicago, Memphis and many other large cities have seen their populations decline since 2000.

Nashville, however, is still growing, adding an estimated 3,800 newcomers last year alone. Its growth rate is dwarfed by the boom in neighboring 'burbs.

Since 2000, Spring Hill's population has increased 154 percent — the second-highest growth rate in the state, behind the burgeoning Memphis suburb of Oakland, whose population ballooned 156 percent. In the same period, while Nashville has grown by 1.2 percent, the population of La Vergne increased by 43 percent, Mt. Juliet by 36 percent, Murfreesboro by 31 percent, Brentwood by 28 percent and Smyrna by 26 percent.

Cities must plan

The more people move in, the more the community changes to cope. Towns such as Murfreesboro have become nonstop construction zones as new homes, new roads and new retail centers go up to serve the new population.

"It certainly requires very careful planning," said Bill Fox, director of the Center for Business and Economic Research at the University of Tennessee. Communities that don't prepare in advance end up struggling after the growth wave hits — widening roads after the traffic jams become intolerable, or adding portable classroom units instead of building new schools, he said.

■ Graphic: Magnet cities in U.S.

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MAGNET CITIES

These Tennessee cities have **attracted the largest number of new residents** over the past five years:

CITY	2006 POPULATION*	5-YEAR GAIN
Murfreesboro	92,559	19,344
Spring Hill	20,768	11,665
Franklin	55,870	8,605
La Vergne	27,255	7,328
Brentwood	33,789	6,847
Nashville	552,120	5,486
Knoxville	182,337	5,469
Collierville	38,678	5,299
Mt. Juliet	19,369	4,514
Hendersonville	46,218	4,336



SOURCE: U.S. Census Bureau

*Estimate

THE TENNESSEAN

Gas distributor Atmos seeks rate increase



JEANNE REASONOVER / THE TENNESSEAN

Scott Workman makes his way around Carronbridge at Cool Springs in Franklin to read meters for Atmos Energy. Atmos, which serves Williamson, Maury, Bedford and Rutherford counties, has asked state lawmakers for a rate increase.

Bills would rise about \$5 in Midstate

by NAOMI SNYDER
Staff Writer

Atmos Energy Corp. said it asked state regulators Friday for an \$11 million rate increase to begin in November that could add about \$5 a month to the average customer's bill. The Dallas-based natural gas distributor has more than 100,000 customers in Williamson, Maury, Bedford and Rutherford counties. The application follows six months on the heels of a regulatory decision that actually cut Atmos' rates by \$6 million. At that time, the Tennessee Regulatory Authority terminated the company had

been making too much money.

But a spokesman for Atmos said the TRA's decision was based on a "snapshot" view of the company's past and that its expenses are climbing.

"It's like an op-ed piece versus a series of articles," said Atmos spokesman Greg Coker. "We want (the TRA) to see the more comprehensive view."

The cost of building new gas lines and other infrastructure normally costs about \$17 million to \$18 million annually.

► Please see **ATMOS, 2E**



JEANNE REASONOVER / THE TENNESSEAN

Scott Workman reads a meter for Atmos Energy in Carronbridge at Cool Springs in Franklin. Dallas-based Atmos had to cut its rates for Tennessee customers six months ago.

The Tennessean
5/5/07

founder, said late on Thursday, at least some of the groups has moved forward a bit.

"The idea has been raised and there have been quite a few

when contacted Friday, Guzman helped start the Nashville Area Hispanic Chamber after leaving the

time."

Yuri Gunza, president of the Nashville Area Hispanic Chamber, is more absolute.

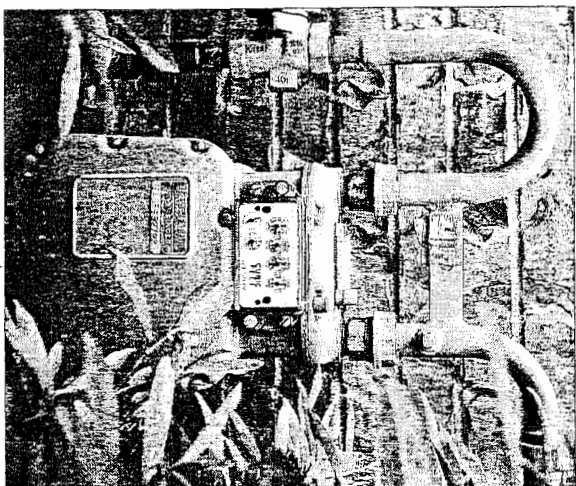
dislike that someone else got dirty," Gunza said.

Janel Ross can be reached at 726-5982 or jross1@tennessean.com.

Atmos: Gas distributor seeks \$11 million rate increase

A gas meter is shown at a home in Franklin. Atmos Energy says it needs to raise its distribution rates to help pay for new gas lines and other infrastructure.

JEANNE REASCOVER / THE TENNESSEAN



FROM PAGE 1E

ally, but the company will have to spend \$25 million on such expenses by the end of October this year, said the company's regulatory affairs director, Pat Childers.

A growing customer base and the cost of replacing about 45,000 feet of aging steel pipe are among other expenses, officials said.

Atmos also is asking for an increase in its profit margin, from 10.47 percent to 11.75 percent.

Retiree says she's 'numb'

"I think we're all getting numb to all these utility price

increases," said Judy Homan, a Murfreesboro retiree who fought Atmos on various billing issues last year, resulting in changes designed to make the company's bills easier to understand. Atmos eventually put her on a new customer advisory board.

Atmos does not make a profit on the cost of delivering it to customers. About 80 percent of the typical customer's bill pays for natural gas.

Atmos hasn't asked for a rate increase for the non-gas portion of its bills in more than 10 years, it said. It bought United Cities Gas Co. in 1997, which had sought and received a rate increase two years before that.

EARNINGS REPORT

National Healthcare Corp. (NHC)

Operator of assisted-living facilities

1st quarter	2006	2007
Revenues	\$137 million	\$146.5 million
Net income	\$5.4 million	\$7 million
Earnings per share	44 cents	56 cents

Big news: Completed construction on a 60-bed addition to its Parklane facility in Columbia, S.C.

Stock price: Closed Friday at \$51.73

American HomePatient Inc. (AHP)

Brentwood-based home health care provider

1st quarter	2006	2007
Revenues	\$79 million	\$76.9 million
Net income (loss)	(\$739,000)	\$1.1 million
Earnings (loss)	(4 cents)	6 cents

Big news: Company said lower revenues were caused by recent Medicare reimbursement cuts and

pilot initiative that makes large-print books available. Since 2005, Lightning Source has worked with National Institute for the Blind to provide large for visually impaired people worldwide.

income, though, reduced operating

Stock price: Clos

RUTHERFORD A.M. COMMUNITY

Meshing shopping lifestyles

Providence gives a preview of The Avenue

By **SCOTT BRODEN**
Gannett Tennessee

MT. JULIET — Local shoppers wanting a preview of what The Avenue shopping center will look like this fall might want to visit Providence Marketplace in Wilson County.

Both retail centers focus on parking near stores and exterior sidewalks and landscaping instead of typical mall designs with large parking lots surrounding sprawling buildings with interior walkways and courts.

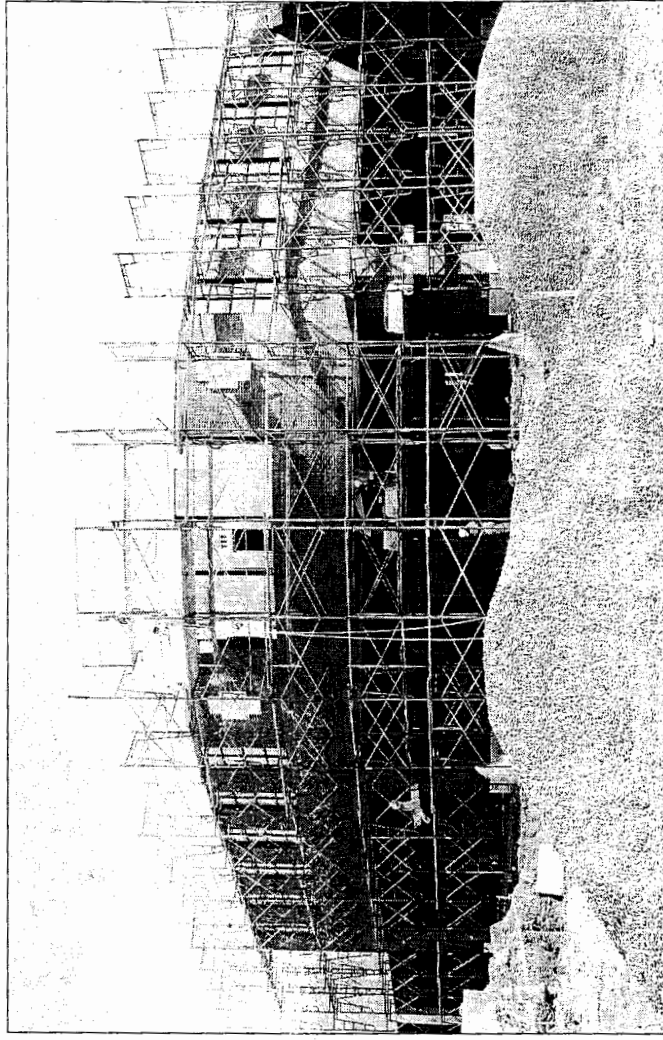
Former Rutherford County resident Carol Farmer was among the shoppers to pull

her car into a Providence area that resembles a typical Main Street setting with a neon-lit 14-screen movie theater nearby.

"I love it," said Farmer, who moved to an apartment within walking distance of the Mt. Juliet shopping center. "It's an outdoor concept. You're not just in the mall. You can just enjoy the outdoors."

Developers building The Avenue off Interstate 24's exit to Medical Center Parkway hope a similar "lifestyle center" will draw shoppers to Murfreesboro when the scheduled grand opening occurs Oct. 17.

"It's a unique combination



Elisa Fisk/Gannett Tennessee

Construction continues at The Avenue, the lifestyles mall where officials project stores will begin opening in August with a grand opening scheduled for October.

of retailers in an environment that's hard to duplicate," said Matt Gove, a spokesman for Cousins Properties.

His Atlanta-based publicly-traded corporation is building The Avenue with Faison Enterprises, a privately owned real estate company in Charlotte, N.C.

Cousins has opened many other shopping centers called The Avenue in the Atlanta area, the Memphis area, and other cities in Florida, California, Minnesota, Missouri and Virginia.

"One of the things that

makes The Avenue special, and particularly The Avenue in Murfreesboro, is the open-air design and pedestrian-friendly nature of the project," Gove said. "It's walkable. It's the kind of place you'll enjoy spending the day at. There will be pocket parks (small landscaped areas with benches and fountains and statues). There will be restaurants. It's not all shopping all the time, and that's what makes The Avenue great."

The Avenue will be about 810,000 square feet when it's fully built-out with about 110

stores. The first 660,000 square feet will open this fall, and work will begin on some undisclosed stores in August, Gove said.

Competition in Wilson County

Providence Marketplace opened its 830,000-square-foot shopping center on 103 acres in March 2006, and more stores will soon add to the 50 or so open now, said Sharon Thompson, manager of the Mt. Juliet shopping center.

► Please see **AVENUE, 13R**

RUTHERFORD A.M.

Avenue: Providence gives a preview

FROM PAGE 12R

"It's very successful," said Thompson, noting how Providence is drawing customers from several Middle Tennessee counties. "We're pulling from as far north as Kentucky."

Many of the stores and future restaurants at Providence resemble the ones along Murfreesboro's Old Fort Parkway, such as Target, Books-A-Million, Staples, Kroger, Old Navy, Red Lobster and Chic-Fil-A.

A few are the same as those planned for The Avenue in Murfreesboro, including Chico's, New York & Company and Lane Bryant.

Providence needs more of the popular retailers heading to The Avenue in Murfreesboro, such as Cold Water Creek and Ann Taylor Loft, said Teresa Freeman, an Old Hickory resident in Davidson County.

She traveled to the Mt. Juliet shopping center with her friend Monica Cox, and both brought a daughter with them. They prefer Providence to Hickory Hollow Mall in the Antioch area in southeast Davidson County just north of La Vergne.

"It's safe," 10-year-old Mikaela Freeman said. "You don't have to worry about someone coming up and saying 'Give me all your stuff or I'll shoot you.'"

Soon-to-be 10-year-old Kirsten Fox said she likes the sporting goods stores and Target store at Providence.

"The theater is nice," Kirsten said. "The food is good. It's fun."

Outdoor appeal

"It's a small-town ambience," said Thompson, the Providence manager.

Among those enjoying the outdoors at Providence recent-

ly was Gary Weatherford. He sat on a bench while his wife, Katy, shopped at New York & Company.

"It's definitely a plus for the community," said Weatherford, who recently moved here from the Memphis area. He and his wife used to shop at The Avenue in Carriage Crossing when they lived in West Tennessee, and they prefer how that retail center blended its anchor stores with the other shops to the way Providence has all its bigger chains lined up in a strip-mall fashion with a sprawling parking lot.

Katy Weatherford likes how shoppers can drive up to their desired store in the section of Providence that resembles a typical Main Street.

"You don't have to go up to the crowded malls," she said. "I just wish more shops would come in and fill up the empty spaces."

Stores within walking distance to homes

The large Providence development includes a neighboring residential component with about 3,200 homes in eight different communities.

Farmer lives in one of those.

"I can walk to the movie theater," said Farmer, who works part-time at a Kroger on South Church Street in south Murfreesboro in the photo processing department, as well as at other Krogers in the region.

She said she feels more rushed when she shops at typical malls, so she'd rather go to Providence Marketplace.

"It's a truer feeling," Farmer said. "It's very European."

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GAS RATE FUNDAMENTALS

Brandeis' prudent investment theory which was introduced in this case than for the majority opinion.

The Supreme Court found that the rates prescribed by the Commission in this case would allow not more than 5½% return upon the minimum rate base, which in the opinion of the Court was wholly inadequate considering the character of the investment and the interest rates then prevailing. The Supreme Court held the rates fixed by the Commission were confiscatory and in conflict with the 14th Amendment and reversed the judgment of the lower court.

Justice Brandeis in his separate opinion said:

"I concur in the judgment of reversal. But I do so on the ground that the order of the state commission prevents the utility from earning a fair return on the amount prudently* invested in it. Thus, I differ fundamentally from my brethren concerning the rule to be applied in determining whether a prescribed rate is confiscatory. The Court, adhering to the so-called rule of *Smyth vs. Ames* (169 U.S. 466), and further defining it, declares that what it termed value must be ascertained by giving weight, among other things, to estimates of what it would cost to reproduce the property at the time of the rate hearing."

After a long and learned discussion of the attributes of various methods of determining value, Justice Brandeis concluded that:

"If the aim were to ascertain the value (in its ordinary sense) of the utility property, the enquiry would be, not what it would cost to reproduce the identical property, but what it would cost to establish a plant which could render the service, or in other words, at what cost could an equally efficient substitute be then produced. Surely the cost of an equally efficient substitute must be the maximum of the rate base, if prudent investment be rejected as the measure. The utilities seem to claim that the constitutional protection against confiscation guarantees them a return both upon unearned increment and upon the cost of property rendered valueless by obsolescence."

Rate of Return—Bluefield Water Works, 1923

In the *Bluefield Water Works and Improvement Company vs. Public Service Commission of West Virginia* (262 U.S. 679), the Supreme Court in 1923 indicated that state commissions must consider similar economic factors in determining the rate of return as in the rate base determination prescribed in *Smyth vs. Ames*. In this case, the Supreme Court said:

"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

* The term 'prudent investment' is not used in a critical sense. There should not be excluded from the finding of the base, investments which, under ordinary circumstances, would be deemed reasonable. The term is applied for the purpose of excluding what might be found to be dishonest or obviously wasteful or imprudent expenditures. Every investment may be assumed to have been made in the exercise of reasonable judgment, unless the contrary is shown."

GUIDING DECISIONS OF COURTS AND COMMISSIONS

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 economic management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties."

What constitutes fair return is one of the controversial items confronting both utility managements and regulatory commissions. The philosophies of the various state regulatory bodies and the Federal Power Commission have many interpretations. The ultimate attainments under such varying philosophies are, of course, subject to many local and practical considerations.

Under the existing regulatory standards, a gas company has the legal right to charge rates which should earn a fair return but there is no guarantee of that fair return. It is up to management to earn that return by revenues collected at the rates established. This being so, no rate or price can be set and let alone. Political and economic forces change rapidly, including the value of the dollar. Public utility rates require careful planning and watchful administration to see that they are reasonable and adequate and thus meet the ever-changing needs of customers and the utility company.

Reproduction Cost Concept—Los Angeles G&E, 1933

During the depression of the early 1930's, in the case of Los Angeles Gas & Electric Corp. vs. California Railroad Commission (289 U.S. 287), the United States Supreme Court in 1933 started its retreat away from required strict adherence to the fair value doctrine laid down in *Smyth vs. Ames*. This case put the Court in favor of considering reproduction cost at the time of investigation. It must be kept in mind that 1933 was a period of depressed prices. The case was an appeal by a gas utility from a Federal District Court's decree refusing to restrain the enforcement of an order of the California Commission reducing gas rates. In affirming the decrees of the lower court the majority opinion (with Justices Butler and Sutherland dissenting) said:

"This Court has further declared that, in order to determine present value, the cost of reproducing the property is a relevant fact which should have appropriate consideration. *Missouri ex rel. Southwestern Bell Telephone Co. vs. Public Service Commission*, supra; *Bluefield Water Works & Improvement Co. vs. West Virginia Pub. Service Commission*, supra; *Standard Oil Co. vs. Southern P. Co.* (1925) 268 U.S. 146, 156, 69 L. ed. 890, 45 S. Ct. 465; *McCardle vs. Indianapolis Water Co.* supra. In *Missouri ex rel. Southwestern Bell Telephone Co. vs. Public Service Commission*, supra, at p. 199 of P. U. R. 1923C, this Court said that 'it is impossible to ascertain what will amount to a fair return upon properties devoted to public service without giving consideration to the cost of labor, supplies, etc., at the time the investigation is made. An honest and intelligent forecast of probable future values, made upon a view of all

GAS RATE FUNDAMENTALS

Third Edition

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A.G.A.

CHOOSING THE TEST YEAR

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The purpose of regulation is to artificially perform the normal economic function of a free enterprise system. Being that utilities are so capital intensive, it is impractical for utilities to compete for customers, raw materials and capital, under normal economic conditions. Therefore, states or towns granted utilities a monopoly or franchise to serve a particular territory. With the guaranteed monopoly came the temptation for undue profits, unfit service, etc., involving the need for regulation -- regulation to take the place of the law of supply and demand which regulate other industries. This is an important point, regulation is expected to act in an artificial economic climate; to determine what price is fair in normal economic conditions; and not necessarily what regulators or customer pressure determine is fair. The utility is not in the protective custody of the regulatory authority, but must compete in the market place with non-regulated industries for financing, labor, raw materials, etc., and utilities MUST have the financial ability to do so.

In order for the utility to compete in the market place, regulations must be fair. Regulators cannot rule on individual issues in isolation. No theory can be pulled out of context; it is the overall picture, the bottom line, that counts. Investors look at the bottom line, the net income, the return on equity that the utility actually earns, not what they should earn, not what some new theory with additions, subtraction, multiplication and division says that the company should earn, but what the utility actually earns. Let's be practical--will the new rates work? Will the utility be financially able to compete in the market place for the necessary resources that are needed to provide safe and adequate service?

My topic is test year, its definition and its use as a rate-making tool. Without a proper test year a company will never earn a proper return on equity.

There are four basic periods of test year:

HISTORICAL TEST YEAR An historical test year is based upon the actual data from the utilities books-actual rate base, actual revenues, actual expenses and actual capitalization. It is easily obtained and verifiable, and the lazy regulators way to establish rate base. The problem is that the rates are based on outdated information. One day after rates are in effect the rates are outdated. A historical test year establishes a level of revenues that only yields an adequate return on historical expenses. What happens when reality occurs? The reality of inflation and growth. The revenues that are based on a historical test year are not sufficient to yield an adequate return. Utilities can never expect to earn adequate rates in the current economy when the rates are set on historical data.

AVERAGE TEST YEAR An average test year is calculated using the beginning and the end of some period of time. Regardless of what period of time, averaging means going backwards. This is particularly unsatisfactory at times when a utility or inflation is growing rapidly, which may be the reason a rate increase is needed in the first place.

PART-ACTUAL AND PART-PROJECTED TEST YEAR -- The test year is part actual and part projected. This concept comes closer to being realistic depending on how far into the future the test year is projected. Unless it is projected far enough into the future, there is no way a utility will earn what the regulators say is an adequate return.

FUTURE -- Test year, revenues, expenses and capitalization are projected to a future period, the future period being the period that the rates will be in effect. When using a future test year, all the components are projected for the year that the rates will be in effect. Rate base will include all construction to be completed during the test year. Revenues from new customers will be anticipated. Increases and decreases in expenses anticipated to occur during the test year

will be incorporated into the income statement. Capitalization will include projected earnings and financing during the test year. All elements of the rate case will be matched for the future year that the rates will be in effect.

In order to measure a return on equity, rates must be in effect for one full year (at minimum and I am not a supporter of annual rate increases). In establishing these rates, the rate base, revenues, expenses and capitalization utilized to set rates, must be those that will be in effect when the rates are in effect. Otherwise, that return, whatever is granted, will never be achieved. A utility does not stand still, revenues, expenses and utility plant all grow. If historical, antiquated, or otherwise outdated test years are used, the rates set will not allow the utility the opportunity to earn an adequate return and therefore to compete in the free market place.

While reading last year's speech on this subject, writer (a regulator) said that "We should be reminded from time to time that a utility is not guaranteed a certain return by regulatory agencies, it is only guaranteed an opportunity to earn a certain return." The key word is opportunity. If the tools used to establish these rates are obsolete, and expenses inflate and construction continues, the utility will never have an opportunity to earn an adequate return. All the changes that will reasonably occur while the rates are in effect, must be reflected when establishing the proper rates. When rates go into effect that are not based on revenues and expenses for the year, and do not consider providing a return on the rate base that will be in effect during the test year, the utility will be guaranteed to earn an inadequate return. Even in the current economic climate, with lower inflation, regulators have to be realistic and set rates on current data; or the revenues generated from this new rate will never cover expenses and provide

anywhere near an adequate return. I would like to use my Company as an example, although I do not want to concentrate on the problems of one Company.

In 1993, the regulators said 12.3% was an adequate return on equity; we earned 12.24%. In 1994 adequate was 11.6%; we earned 11.51%. In 1995 adequate was 11.50%; we earned 11.82%, due to a very hot and dry summer. In 1996 adequate was 11.50%, we earned 9.46% the results were effected by excess rainfall, and in 1997 adequate was 11.6%, we earned 9.9%, with a record breaking hot, dry summer. In 1998, adequate was 11.25% and we earned 9.0%. Obviously there was something wrong with the way regulation was working, or most specifically, with the selection of a test year. In our current case, since we can utilize only certain components of a future test year in our state, we will again probably not earn the granted adequate return.

Most regulators are hesitant at any idea of future test year. There is a fear that the projections will be based on wild estimates of expenses and revenues. But that is not the case -- projections can be valid for one full year in the future. In the areas of rate base, projections of future constructions can be validated from past performances of construction budgets, review of preliminary plans and construction contracts to verify that the utility is actually undertaking such a program. Budgets for revenues and expenses can be reviewed from prior years as a check on the accuracy of the projections. The utility can be required to submit actual construction expenditures and income statements after rates are in effect. It is not speculation to select a future test year -- it's the only realistic way. By disallowing projections for the increase in expenses, the increases will not go away. Not recognizing inflation will not stop inflation from happening.

Very simply speaking, there are 4 tools for setting rates; rate base, operating revenues net of expenses (utility operating income), capitalization and cost of money. Rate base is the utility's investment in utility plant and the working capital necessary to purify and distribute water. Cost of capital (rate of return) is weighted average cost of stockholder supplied funds (equity) and investor supplied funds (debt). The composite rate of return is multiplied by rate base to determine the necessary utility operating income. This is the amount of revenues that the utility should be collecting. In the case of deficiency, when compared to actual or projected utility operating income, a rate increase is in order.

Test year is the time period, or year, that is utilized to calculate a rate increase. The test year cost of money, based on test year capitalization, is multiplied times test year rate base. The result is the utility operating income that the utility should be earning. When this operating income is compared to the test year operating income that the utility will earn, the deficiency determines the necessary rate increase. It becomes apparent how important the selection of a proper test year is, as it is the basic ingredient for setting rates. Another important point is that all the components match. Rate base, revenues, expenses, and capitalization must be calculated for the same period of time. Revenues should include new customers from increased rate base; depreciation expense should be based on test year utility plant; operating expenses should reflect increases or economies for test year base; the components must match.

Arguments are also advanced, that present customers who pay the rates that pay for a project may not be the ultimate consumer. Although, some people will pay for projects that they will use, it must be viewed in the concept of the entire case-- rates cannot be set daily-- they have to be set for a period of time-- and include the anticipated changes for that period of time. If one views the present customer paying part of the project as discrimination, then who should bear the cost of financing a project until it is included in rate base. The stockholder? It is equally discriminating against the stockholder who usually never earns an adequate return. In one of our cases approximately 5% of our current utility plant was for future construction; construction that is necessary. If a customer moved within a year, that customer would pay \$2.45 for the utility plant that the customer would not benefit from and the total paid for all the customers moving within a year is only \$28,000.

In conclusion, deciding on a proper test year must be the first step in deciding a rate case. You Commissioners must decide on the proper test year for the Suburban Water Company. Of course, you can determine any test year that you wish. But, unless you choose a test year that allows for known and anticipated changes in the expenses and revenues of Suburban Water Company and allows for the inclusion of projects that will be completed during the test year, the Suburban Water Company will never earn the return on equity that you as Commissioners determine to be adequate.

Table 6. Population for the 15 Largest Counties and Incorporated Places in Tennessee: 1990 and 2000

NOTE: Data not adjusted based on the Accuracy and Coverage Evaluation. For information on confidentiality protection, sampling error, nonsampling error, and definitions, see <http://factfinder.census.gov/home/en/datanotes/expplu.html>.

Population rank		Geographic area	Population		Population change, 1990 to 2000	
2000	1990		2000	1990 ¹	Number	Percent
		Tennessee	5 689 283	4 877 185	812 098	16.7
		COUNTY				
1	1	Shelby County	897 472	826 330	71 142	8.6
2	2	Davidson County ²	569 891	510 784	59 107	11.6
3	3	Knox County	382 032	335 749	46 283	13.8
4	4	Hamilton County	307 896	285 536	22 360	7.8
5	6	Rutherford County	182 023	118 570	63 453	53.5
6	5	Sullivan County	153 048	143 596	9 452	6.6
7	8	Montgomery County	134 768	100 498	34 270	34.1
8	7	Sumner County	130 449	103 281	27 168	26.3
9	11	Williamson County	126 638	81 021	45 617	56.3
10	9	Washington County	107 198	92 315	14 883	16.1
11	10	Blount County	105 823	85 969	19 854	23.1
12	12	Madison County	91 837	77 982	13 855	17.8
13	15	Wilson County	88 809	67 675	21 134	31.2
14	13	Bradley County	87 965	73 712	14 253	19.3
15	14	Anderson County	71 330	68 250	3 080	4.5
		INCORPORATED PLACE				
1	1	Memphis city	650 100	610 337	39 763	6.5
2	2	Nashville-Davidson ²	569 891	510 784	59 107	11.6
3	3	Knoxville city	173 890	165 121	8 769	5.3
4	4	Chattanooga city	155 554	152 466	3 088	2.0
5	5	Clarksville city	103 455	75 494	27 961	37.0
6	8	Murfreesboro city	68 816	44 922	23 894	53.2
7	7	Jackson city	59 643	48 949	10 694	21.8
8	6	Johnson City city	55 469	49 381	6 088	12.3
9	9	Kingsport city	44 905	36 365	8 540	23.5
10	20	Franklin city	41 842	20 098	21 744	108.2
11	11	Hendersonville city	40 620	32 188	8 432	26.2
12	15	Bartlett city	40 543	26 989	13 554	50.2
13	10	Germantown city	37 348	32 893	4 455	13.5
14	12	Cleveland city	37 192	30 354	6 838	22.5
15	13	Columbia city	33 055	28 583	4 472	15.6

- Represents zero or rounds to 0.0.

¹ 1990 census counts are as published in 1990 census reports and thus do not include any changes published subsequently due to boundary changes or to the Count Question Resolution program.

² Davidson County and the incorporated place of Nashville-Davidson are coextensive.

Source: U.S. Census Bureau, Census 2000 Redistricting Data (P.L. 94-171) Summary File, Table PL1, and 1990 census.

U.S. Census Bureau

American FactFinder



Tennessee -- County

GCT-T1-R. Population Estimates (geographies ranked by estimate)

Data Set: 2006 Population Estimates

Note: For information on errors stemming from model error, sampling error, and nonsampling error, see: <http://www.census.gov/popest/topics/methodology>.

Rank	Geographic area	Population Estimates							Estimates Base	Census 2000
		July 1, 2006	July 1, 2005	July 1, 2004	July 1, 2003	July 1, 2002	July 1, 2001	July 1, 2000	April 1, 2000	April 1, 2000
	Tennessee	6,038,803	5,955,745	5,885,597	5,834,358	5,788,333	5,746,477	5,703,299	5,689,262	5,689,283
	COUNTY									
1	Shelby County	911,438	905,705	903,362	902,205	900,244	898,197	898,214	897,472	897,472
2	Davidson County	578,698	574,395	571,159	569,068	568,964	571,223	569,990	569,892	569,891
3	Knox County	411,967	405,355	400,174	396,559	391,462	387,184	382,835	382,032	382,032
4	Hamilton County	312,905	310,659	309,338	309,067	309,067	308,467	308,033	307,908	307,896
5	Rutherford County	228,829	218,478	209,634	201,973	195,578	189,414	183,482	182,023	182,023
6	Williamson County	160,781	153,445	146,953	141,453	136,667	132,475	128,127	126,638	126,638
7	Sullivan County	153,239	152,535	152,086	152,665	152,707	152,434	152,953	153,048	153,048
8	Sumner County	149,416	144,769	141,622	138,548	136,407	133,787	131,171	130,448	130,449
9	Montgomery County	147,114	146,845	141,406	139,033	136,731	135,581	135,242	134,768	134,768
10	Blount County	118,186	115,616	113,406	111,311	109,656	108,023	106,255	105,823	105,823
11	Washington County	114,316	112,422	110,827	109,892	109,109	107,529	107,478	107,198	107,198
12	Wilson County	104,035	100,471	97,700	95,436	93,404	91,352	89,294	88,808	88,809
13	Madison County	95,894	94,673	94,054	93,623	93,332	92,836	92,018	91,837	91,837
14	Bradley County	93,538	92,136	91,052	89,954	89,472	88,871	88,186	87,953	87,965
15	Sevier County	81,382	79,339	77,066	75,507	74,308	73,135	71,713	71,170	71,170
16	Maury County	78,309	76,228	74,642	73,038	71,469	70,258	69,738	69,498	69,498
17	Anderson County	73,579	72,518	72,004	71,856	71,663	71,452	71,298	71,330	71,330
18	Putnam County	68,284	66,867	65,767	64,858	64,044	63,140	62,472	62,315	62,315
19	Greene County	65,945	65,248	64,581	64,073	63,691	63,387	63,055	62,909	62,909
20	Robertson County	62,187	60,361	59,175	58,167	57,209	56,077	54,861	54,434	54,433
21	Hamblen County	61,026	60,191	59,371	58,859	58,477	58,849	58,249	58,128	58,128
22	Carter County	59,157	58,884	58,600	58,414	56,889	56,936	56,843	56,742	56,742
23	Tipton County	57,380	55,999	54,589	54,025	53,326	52,776	51,561	51,271	51,271
24	Hawkins County	56,850	56,203	55,575	55,158	54,696	54,221	53,716	53,563	53,563
25	Roane County	53,293	52,753	52,719	52,439	52,211	51,974	51,956	51,910	51,910
26	Cumberland County	52,344	51,151	50,092	49,242	48,676	47,725	47,029	46,804	46,802
27	McMinn County	52,020	51,338	50,804	50,483	50,107	49,778	49,177	49,010	49,015
28	Coffee County	51,625	50,876	50,086	49,662	49,173	48,601	48,183	48,014	48,014
29	Jefferson County	49,372	48,261	47,517	46,911	45,823	45,102	44,593	44,294	44,294
30	Gibson County	48,461	48,061	47,952	47,802	48,099	48,070	48,171	48,149	48,152
31	Dickson County	46,583	45,822	45,287	44,915	44,291	43,781	43,340	43,156	43,156

Rank	Geographic area	Population Estimates							Estimates Base	Census 2000
		July 1, 2006	July 1, 2005	July 1, 2004	July 1, 2003	July 1, 2002	July 1, 2001	July 1, 2000	April 1, 2000	April 1, 2000
32	Loudon County	44,566	43,411	42,226	41,568	40,762	39,962	39,232	39,087	39,086
33	Monroe County	44,163	43,184	42,117	41,072	40,387	39,666	39,188	38,965	38,961
34	Bedford County	43,413	42,287	41,203	40,170	39,281	38,572	37,834	37,586	37,586
35	Franklin County	41,319	40,871	40,629	40,394	40,104	39,739	39,350	39,270	39,270
36	Lawrence County	40,934	40,985	40,726	40,640	40,617	40,083	39,965	39,926	39,926
37	Campbell County	40,848	40,558	40,481	40,016	39,870	39,831	39,883	39,794	39,854
38	Warren County	40,016	39,617	39,422	39,242	38,785	38,717	38,412	38,276	38,276
39	Cheatham County	39,018	38,525	37,953	37,265	37,085	36,593	36,117	35,912	35,912
40	Dyer County	37,886	37,773	37,468	37,275	37,127	37,168	37,331	37,279	37,279
41	Fayette County	36,102	34,418	33,443	32,252	31,149	30,281	29,122	28,796	28,806
42	Cocke County	35,220	34,877	34,583	34,368	34,103	33,686	33,623	33,565	33,565
43	Weakley County	33,357	33,607	33,645	34,059	34,274	34,386	34,903	34,895	34,895
44	Lincoln County	32,728	32,385	31,977	31,864	31,698	31,571	31,417	31,340	31,340
45	Obion County	32,184	32,177	32,319	32,301	32,411	32,397	32,502	32,450	32,450
46	Henry County	31,837	31,475	31,275	31,195	31,319	31,197	31,139	31,102	31,115
47	Claiborne County	31,347	31,073	30,747	30,508	30,142	30,172	29,981	29,922	29,862
48	Rhea County	30,347	29,872	29,616	29,357	28,944	28,646	28,470	28,403	28,400
49	Giles County	29,269	29,213	29,223	29,286	29,459	29,629	29,469	29,447	29,447
50	Carroll County	29,096	29,014	29,306	29,401	29,344	29,619	29,476	29,486	29,475
51	Marshall County	28,884	28,330	27,930	27,550	27,418	27,170	26,880	26,767	26,767
52	Hardeman County	28,176	28,091	28,041	28,109	28,230	28,248	28,134	28,105	28,105
53	Marion County	27,942	27,715	27,686	27,806	27,778	27,799	27,777	27,776	27,776
54	Henderson County	26,750	26,371	26,171	25,967	25,829	25,684	25,610	25,522	25,522
55	Lauderdale County	26,732	26,672	26,707	27,004	27,108	27,151	27,050	27,101	27,101
56	Hardin County	26,089	26,002	25,783	25,873	25,917	25,771	25,586	25,578	25,578
57	McNairy County	25,722	25,323	25,074	24,886	24,699	24,660	24,721	24,665	24,653
58	White County	24,482	24,206	23,853	23,534	23,484	23,421	23,137	23,104	23,102
59	Hickman County	23,812	23,726	23,643	23,269	23,213	22,723	22,441	22,295	22,295
60	Grainger County	22,453	22,188	21,836	21,527	21,194	20,940	20,722	20,659	20,659
61	Scott County	21,926	21,855	21,736	21,656	21,676	21,537	21,182	21,127	21,127
62	Macon County	21,726	21,564	21,341	21,028	20,861	20,889	20,455	20,386	20,386
63	Overton County	20,740	20,498	20,446	20,146	20,244	20,222	20,197	20,118	20,118
64	Morgan County	20,108	20,086	20,083	20,073	20,042	20,011	19,785	19,755	19,757
65	Haywood County	19,405	19,423	19,581	19,546	19,567	19,829	19,823	19,797	19,797
66	Union County	19,086	19,005	18,860	18,805	18,557	18,333	17,872	17,808	17,808
67	Smith County	18,753	18,579	18,378	18,289	18,170	17,970	17,817	17,712	17,712
68	Humphreys County	18,394	18,208	18,083	18,103	18,076	18,115	17,930	17,929	17,929
69	DeKalb County	18,360	18,299	18,158	17,995	17,779	17,609	17,463	17,421	17,423
70	Johnson County	18,043	18,077	18,004	17,967	17,809	17,757	17,516	17,499	17,499
71	Unicoi County	17,663	17,599	17,649	17,700	17,647	17,573	17,656	17,667	17,667
72	Fentress County	17,480	17,180	16,937	16,977	16,864	16,700	16,645	16,625	16,625
73	Wayne County	16,828	16,848	16,871	16,903	17,025	17,066	16,835	16,842	16,842
74	Benton County	16,378	16,476	16,457	16,533	16,567	16,663	16,532	16,537	16,537
75	Chester County	16,043	15,875	15,776	15,528	15,913	15,815	15,548	15,528	15,540
76	Polk County	15,939	16,023	15,945	16,137	16,114	16,214	16,104	16,050	16,050
77	Grundy County	14,499	14,564	14,483	14,367	14,315	14,247	14,332	14,332	14,332
78	Crockett County	14,392	14,499	14,543	14,452	14,528	14,558	14,547	14,532	14,532
79	Cannon County	13,448	13,341	13,273	13,187	13,101	13,065	12,916	12,826	12,826
80	Bledsoe County	13,030	12,902	12,785	12,595	12,498	12,502	12,413	12,364	12,367

Rank	Geographic area	Population Estimates							Estimates Base	Census 2000
		July 1, 2006	July 1, 2005	July 1, 2004	July 1, 2003	July 1, 2002	July 1, 2001	July 1, 2000	April 1, 2000	April 1, 2000
81	Sequatchie County	13,002	12,707	12,331	12,033	11,793	11,538	11,415	11,370	11,370
82	Stewart County	12,998	12,975	12,779	12,838	12,790	12,601	12,450	12,370	12,370
83	Meigs County	11,698	11,595	11,500	11,370	11,307	11,232	11,131	11,086	11,086
84	Lewis County	11,588	11,426	11,452	11,483	11,435	11,451	11,376	11,367	11,367
85	Decatur County	11,426	11,586	11,678	11,614	11,712	11,770	11,708	11,731	11,731
86	Jackson County	10,918	11,072	11,141	11,171	11,176	11,177	11,030	10,984	10,984
87	Houston County	8,076	8,027	7,941	8,048	7,991	8,036	8,024	8,088	8,088
88	Clay County	8,055	8,013	7,999	7,942	7,969	7,966	7,985	7,976	7,976
89	Trousdale County	7,811	7,648	7,500	7,448	7,397	7,368	7,324	7,259	7,259
90	Perry County	7,653	7,631	7,614	7,639	7,545	7,517	7,644	7,631	7,631
91	Lake County	7,406	7,544	7,625	7,870	7,883	7,954	7,942	7,954	7,954
92	Hancock County	6,713	6,730	6,681	6,633	6,750	6,792	6,776	6,780	6,786
93	Moore County	6,070	6,037	5,984	5,909	5,963	5,832	5,768	5,740	5,740
94	Van Buren County	5,448	5,436	5,436	5,475	5,532	5,462	5,518	5,508	5,508
95	Pickett County	4,855	4,867	4,864	4,944	5,054	4,989	4,935	4,945	4,945

Source: U.S. Census Bureau, Population Estimates Program
 More Tables and Information: Population Estimates Program

NOTE: The April 1, 2000 Estimates Base reflects modifications to the Census 2000 population as documented in the Count Question Resolution program, updates from the Boundary and Annexation Survey, and geographic program revisions. An "(X)" for the Census 2000 value indicates a locality that was formed or incorporated after Census 2000 or was erroneously omitted from Census 2000. See Geographic Change Notes for additional information on these localities.

County Population Estimates Components of Change: 2000 to 2006

Area	Total Population							Births						
	2006	2005	2004	2003	2002	2001	Census 2000	2006	2005	2004	2003	2002	2001	2000*
TENNESSEE	6,038,803	5,955,745	5,885,597	5,834,358	5,788,333	5,746,477	5,689,283	80,460	79,836	79,659	77,698	77,695	79,258	19,275
Anderson	73,579	72,518	72,004	71,856	71,663	71,452	71,330	869	848	827	802	795	797	200
Bedford	43,413	42,287	41,203	40,170	39,281	38,572	37,586	674	657	639	579	600	592	152
Benton	16,378	16,476	16,457	16,533	16,567	16,663	16,537	178	163	164	149	175	166	38
Bledsoe	13,030	12,902	12,785	12,595	12,498	12,502	12,367	124	133	134	124	122	135	43
Blount	118,186	115,616	113,406	111,311	109,656	108,023	105,823	1,338	1,338	1,346	1,293	1,250	1,313	327
Bradley	93,538	92,136	91,052	89,954	89,472	88,871	87,965	1,163	1,205	1,231	1,161	1,196	1,145	288
Campbell	40,848	40,558	40,481	40,016	39,870	39,831	39,854	479	484	523	488	454	492	119
Cannon	13,448	13,341	13,273	13,187	13,101	13,065	12,826	122	135	136	151	153	152	31
Carroll	29,096	29,014	29,306	29,401	29,344	29,619	29,475	337	330	347	347	368	362	80
Carter	59,157	58,884	58,600	58,414	56,889	56,936	56,742	632	637	645	584	570	557	163
Cheatham	39,018	38,525	37,953	37,265	37,085	36,593	35,912	493	493	487	474	489	472	119
Chester	16,043	15,875	15,776	15,528	15,913	15,815	15,540	189	186	182	190	184	175	40
Claborn	31,347	31,073	30,747	30,508	30,142	30,172	29,862	367	357	356	348	361	352	88
Clay	8,055	8,013	7,999	7,942	7,969	7,966	7,976	128	112	79	78	81	88	21
Cocke	35,220	34,877	34,583	34,368	34,103	33,686	33,565	400	403	418	429	421	407	84
Coffee	51,625	50,876	50,086	49,662	49,173	48,601	48,014	741	711	654	653	627	664	178
Crockett	14,392	14,499	14,543	14,452	14,528	14,558	14,532	154	158	183	180	217	191	37
Cumberland	52,344	51,151	50,092	49,242	48,676	47,725	46,802	542	516	495	535	478	515	123
Davidson ¹	578,698	574,395	571,159	569,068	568,964	571,223	569,891	9,103	9,036	9,030	8,715	8,796	8,928	2,136
Decatur	11,426	11,586	11,678	11,614	11,712	11,770	11,731	101	116	130	119	134	136	26
DeKalb	18,360	18,299	18,158	17,995	17,779	17,609	17,423	221	247	254	221	208	229	43
Dickson	46,583	45,822	45,287	44,915	44,291	43,781	43,156	655	645	612	648	653	622	148
Dyer	37,886	37,773	37,468	37,275	37,127	37,168	37,279	507	503	513	458	523	523	116
Fayette	36,102	34,418	33,443	32,252	31,149	30,281	28,806	443	407	386	408	386	425	98
Fentress	17,480	17,180	16,937	16,977	16,864	16,700	16,625	199	209	200	204	217	201	47
Franklin	41,319	40,871	40,629	40,394	40,104	39,739	39,270	456	447	447	476	447	450	116
Gibson	48,461	48,061	47,952	47,802	48,099	48,070	48,152	598	606	611	588	630	634	174
Giles	29,269	29,213	29,223	29,286	29,459	29,629	29,447	308	316	348	339	318	350	76
Grainger	22,453	22,188	21,836	21,527	21,194	20,940	20,659	237	235	250	290	266	256	55
Greene	65,945	65,248	64,581	64,073	63,691	63,387	62,909	758	716	732	706	703	749	199
Grundy	14,499	14,564	14,483	14,367	14,315	14,247	14,332	185	196	210	198	192	208	45
Hamblen	61,026	60,191	59,371	58,859	58,477	58,849	58,128	872	838	804	826	808	849	223
Hamilton	312,905	310,659	309,338	309,067	309,067	308,467	307,896	3,944	3,993	4,031	3,879	3,897	4,079	986

Source: Population Estimates Program, U.S. Bureau of the Census

County Population Estimates Components of Change: 2000 to 2006

Area	Total Population						Births								
	2006	2005	2004	2003	2002	2001	Census 2000	2006	2005	2004	2003	2002	2001	2000*	
Hancock	6,713	6,730	6,681	6,633	6,750	6,792	6,786	99	94	87	62	67	76	20	
Hardeman	28,176	28,091	28,041	28,109	28,230	28,248	28,105	331	332	328	349	340	317	96	
Hardin	26,089	26,002	25,783	25,873	25,917	25,771	25,578	275	274	293	254	281	281	59	
Hawkins	56,850	56,203	55,575	55,158	54,696	54,221	53,563	684	657	658	650	612	647	158	
Haywood	19,405	19,423	19,581	19,546	19,567	19,829	19,797	293	264	281	286	289	293	79	
Henderson	26,750	26,371	26,171	25,967	25,829	25,684	25,522	308	337	377	350	363	352	73	
Henry	31,837	31,475	31,275	31,195	31,319	31,197	31,115	423	373	332	328	382	373	93	
Hickman	23,812	23,726	23,643	23,269	23,213	22,723	22,295	250	266	274	280	280	310	72	
Houston	8,076	8,027	7,941	8,048	7,991	8,036	8,088	126	109	101	98	91	109	20	
Humphreys	18,394	18,208	18,083	18,103	18,076	18,115	17,929	251	236	211	220	220	217	54	
Jackson	10,918	11,072	11,141	11,171	11,176	11,177	10,984	110	124	126	94	97	106	32	
Jefferson	49,372	48,261	47,517	46,911	45,823	45,102	44,294	528	525	526	507	525	521	140	
Johnson	18,043	18,077	18,004	17,967	17,809	17,757	17,499	176	167	160	160	156	149	40	
Knox	411,967	405,355	400,174	396,559	391,462	387,184	382,032	5,125	5,102	5,059	4,863	4,750	4,828	1,232	
Lake	7,406	7,544	7,625	7,870	7,883	7,954	7,954	65	70	73	92	60	81	17	
Lauderdale	26,732	26,672	26,707	27,004	27,108	27,151	27,101	350	364	390	396	406	418	90	
Lawrence	40,934	40,985	40,726	40,640	40,617	40,083	39,926	532	563	599	596	580	632	120	
Lewis	11,588	11,426	11,452	11,483	11,435	11,451	11,367	158	170	182	171	120	132	37	
Lincoln	32,728	32,385	31,977	31,864	31,698	31,571	31,340	463	433	390	400	373	389	93	
Loudon	44,566	43,411	42,226	41,568	40,762	39,962	39,086	543	512	494	479	483	490	114	
McMinn	52,020	51,338	50,804	50,483	50,107	49,778	49,015	631	617	602	599	613	630	141	
McNairy	25,722	25,323	25,074	24,886	24,699	24,660	24,653	346	344	337	326	355	340	92	
Macon	21,726	21,564	21,341	21,028	20,861	20,889	20,386	265	268	258	271	260	275	61	
Madison	95,894	94,673	94,054	93,623	93,332	92,836	91,837	1,322	1,345	1,362	1,319	1,325	1,372	304	
Marion	27,942	27,715	27,686	27,806	27,778	27,799	27,776	316	326	378	320	310	373	71	
Marshall	28,884	28,330	27,930	27,550	27,418	27,170	26,767	343	359	366	362	390	359	95	
Maury	78,309	76,228	74,642	73,038	71,469	70,258	69,498	983	1,003	1,027	1,000	986	1,029	244	
Meigs	11,698	11,595	11,500	11,370	11,307	11,232	11,086	79	117	142	139	147	159	45	
Monroe	44,163	43,184	42,117	41,072	40,387	39,666	38,961	541	557	560	533	533	529	109	
Montgomery	147,114	146,845	141,406	139,033	136,731	135,581	134,768	2,716	2,366	2,161	2,300	2,350	2,471	587	
Moore	6,070	6,037	5,984	5,909	5,963	5,832	5,740	53	61	61	51	66	51	15	
Morgan	20,108	20,086	20,083	20,073	20,042	20,011	19,757	211	216	219	229	213	230	47	
Obion	32,184	32,177	32,319	32,301	32,411	32,397	32,450	420	413	382	425	434	425	107	
Overton	20,740	20,498	20,446	20,146	20,244	20,222	20,118	280	269	261	211	227	240	70	

Source: Population Estimates Program, U.S. Bureau of the Census

County Population Estimates Components of Change: 2000 to 2006

Area	Total Population							Births						
	2006	2005	2004	2003	2002	2001	Census 2000	2006	2005	2004	2003	2002	2001	2000*
Perry	7,653	7,631	7,614	7,639	7,545	7,517	7,631	97	98	92	105	96	83	19
Pickett	4,855	4,867	4,864	4,944	5,054	4,989	4,945	57	63	61	47	59	46	9
Polk	15,939	16,023	15,945	16,137	16,114	16,214	16,050	171	201	204	209	209	198	56
Putnam	68,284	66,867	65,767	64,858	64,044	63,140	62,315	893	926	896	875	812	840	238
Rhea	30,347	29,872	29,616	29,357	28,944	28,646	28,400	432	394	397	406	366	402	92
Roane	53,293	52,753	52,719	52,439	52,211	51,974	51,910	517	501	512	532	545	631	150
Robertson	62,187	60,361	59,175	58,167	57,209	56,077	54,433	982	958	940	870	863	833	224
Rutherford	228,829	218,478	209,634	201,973	195,578	189,414	182,023	3,422	3,345	3,219	3,058	2,959	2,936	655
Scott	21,926	21,855	21,736	21,656	21,676	21,537	21,127	298	318	331	317	348	304	76
Sequatchie	13,002	12,707	12,331	12,033	11,793	11,538	11,370	136	160	174	157	157	128	27
Sevier	81,382	79,339	77,066	75,507	74,308	73,135	71,170	1,040	980	925	976	903	931	222
Shelby	911,438	905,705	903,362	902,205	900,244	898,197	897,472	14,345	14,301	14,326	14,146	14,270	14,578	3,566
Smith	18,753	18,579	18,378	18,289	18,170	17,970	17,712	215	214	218	214	205	236	56
Stewart	12,998	12,975	12,779	12,838	12,790	12,601	12,370	146	147	138	160	152	155	31
Sullivan	153,239	152,535	152,086	152,665	152,707	152,434	153,048	1,523	1,539	1,617	1,584	1,631	1,766	428
Sumner	149,416	144,769	141,622	138,548	136,407	133,787	130,449	1,854	1,850	1,909	1,779	1,786	1,805	443
Tipton	57,380	55,999	54,589	54,025	53,326	52,776	51,271	706	747	748	665	734	707	189
Trousdale	7,811	7,648	7,500	7,448	7,397	7,368	7,259	103	90	95	79	85	92	26
Unicoi	17,663	17,599	17,649	17,700	17,647	17,573	17,667	182	191	181	169	184	177	49
Union	19,086	19,005	18,860	18,805	18,557	18,333	17,808	243	231	235	250	244	225	53
Van Buren	5,448	5,436	5,436	5,475	5,532	5,462	5,508	57	49	56	55	65	49	15
Warren	40,016	39,617	39,422	39,242	38,785	38,717	38,276	570	524	496	559	610	541	141
Washington	114,316	112,422	110,827	109,892	109,109	107,529	107,198	1,341	1,359	1,376	1,325	1,262	1,280	351
Wayne	16,828	16,848	16,871	16,903	17,025	17,066	16,842	162	170	174	154	159	175	43
Weakley	33,357	33,607	33,645	34,059	34,274	34,386	34,895	346	328	342	348	382	408	89
White	24,482	24,206	23,853	23,534	23,484	23,421	23,102	300	295	304	294	269	320	72
Williamson	160,781	153,445	146,953	141,453	136,667	132,475	126,638	1,932	1,950	1,943	1,756	1,681	1,703	434
Wilson	104,035	100,471	97,700	95,436	93,404	91,352	88,809	1,277	1,298	1,289	1,249	1,256	1,291	275

County Population Estimates Components of Change: 2000 to 2006

Area	Deaths										International Migration				
	2006	2005	2004	2003	2002	2001	2000*	2006	2005	2004	2003	2002	2001	2000*	
TENNESSEE	57,574	56,115	57,349	56,357	55,742	55,540	12,938	9,719	9,056	9,711	7,062	10,001	10,828	3,008	
Anderson	766	830	903	812	821	804	198	86	85	84	82	96	97	22	
Bedford	416	394	380	408	377	384	87	230	230	218	236	272	272	73	
Benton	241	217	206	218	240	214	53	1	1	1	0	0	1	0	
Bledsoe	104	107	121	109	114	117	31	2	2	2	1	1	2	0	
Blount	1,183	1,168	1,221	1,213	1,140	1,070	253	101	92	101	60	93	104	26	
Bradley	829	799	839	805	768	795	182	122	122	115	126	142	143	35	
Campbell	483	463	471	458	509	440	106	29	28	28	26	31	32	6	
Cannon	153	149	144	146	136	149	30	5	5	5	8	8	8	0	
Carroll	407	399	430	405	423	456	104	10	10	11	8	8	10	0	
Carter	645	647	686	652	619	635	165	22	22	20	21	29	30	4	
Cheatham	283	277	298	278	279	252	66	12	11	13	3	8	11	4	
Chester	133	131	135	162	138	179	33	6	6	6	5	7	8	1	
Claiborne	365	332	341	328	378	359	83	22	22	22	23	27	27	4	
Clay	122	117	112	113	107	92	18	5	5	6	4	5	6	0	
Cocke	478	447	440	428	402	429	82	8	8	9	6	8	8	1	
Coffee	578	585	582	564	540	561	110	65	62	64	52	64	67	19	
Crockett	222	190	190	192	198	180	44	24	24	29	36	38	38	3	
Cumberland	546	538	523	598	539	552	131	10	10	10	9	11	11	3	
Davidson ¹	5,026	4,893	5,078	5,223	5,069	5,061	1,202	2,744	2,729	2,589	2,799	3,223	3,237	840	
Decatur	180	169	161	183	162	150	32	13	13	14	13	15	16	1	
DeKalb	222	227	242	174	177	206	40	41	41	38	43	49	50	16	
Dickson	426	407	447	446	430	355	94	7	6	9	5	8	10	2	
Dyer	372	406	445	415	427	451	107	36	35	35	36	42	43	13	
Fayette	327	336	331	282	301	288	61	7	7	7	6	8	8	1	
Fentress	226	203	206	228	214	199	42	4	4	4	3	3	4	0	
Franklin	473	439	430	398	411	438	93	29	28	30	25	31	34	8	
Gibson	625	656	695	726	686	719	154	21	21	23	22	26	26	7	
Giles	412	401	380	385	342	328	85	10	10	11	13	13	13	2	
Grainger	244	238	220	228	232	200	49	16	16	15	15	16	17	2	
Greene	730	712	705	772	775	703	155	53	52	50	48	63	65	18	
Grundy	203	167	150	171	170	205	42	0	0	0	0	0	1	0	
Hamblen	619	628	668	636	642	576	151	318	317	298	329	373	375	99	
Hamilton	3,312	3,246	3,264	3,101	3,157	3,248	749	492	486	464	481	558	566	149	

Source: Population Estimates Program, U.S. Bureau of the Census

County Population Estimates Components of Change: 2000 to 2006

Area	Deaths							International Migration						
	2006	2005	2004	2003	2002	2001	2000*	2006	2005	2004	2003	2002	2001	2000*
Hancock	75	71	82	82	90	90	20	0	0	0	-1	-1	0	0
Hardeman	291	278	284	293	288	292	80	4	4	4	3	5	5	1
Hardin	386	357	353	320	329	344	74	5	5	5	5	6	8	2
Hawkins	580	572	587	566	547	518	124	19	18	17	13	20	22	8
Haywood	231	215	210	224	229	233	56	20	20	20	19	23	23	4
Henderson	300	323	357	308	319	303	71	2	2	4	2	4	4	0
Henry	445	436	446	409	429	437	111	14	13	13	9	13	15	3
Hickman	233	216	226	249	226	234	53	1	1	2	-1	0	1	0
Houston	106	109	122	112	114	86	23	8	8	6	10	10	10	4
Humphreys	243	228	222	205	216	191	46	3	3	3	4	4	4	0
Jackson	170	147	136	129	139	157	33	3	3	2	2	2	3	1
Jefferson	493	479	452	470	436	433	104	60	60	56	59	70	71	14
Johnson	216	209	206	185	226	190	41	2	2	2	1	1	2	0
Knox	3,714	3,639	3,769	3,580	3,597	3,713	830	471	465	443	459	544	553	156
Lake	106	101	93	103	102	122	23	2	2	2	2	3	3	0
Lauderdale	321	287	258	291	299	301	69	13	13	13	13	15	15	3
Lawrence	473	488	485	436	425	400	90	14	14	15	13	16	18	3
Lewis	117	146	161	145	121	117	33	3	3	4	2	5	5	0
Lincoln	383	374	379	347	395	386	99	16	15	15	12	18	19	5
Loudon	460	460	471	471	442	428	105	33	33	31	33	37	38	9
McMinn	610	581	587	543	560	485	109	34	33	34	27	37	39	7
McNairy	303	311	349	314	307	331	81	8	8	11	14	16	16	1
Macon	259	235	224	222	232	205	49	34	34	31	34	42	42	8
Madison	915	875	863	908	864	868	209	148	147	142	149	178	179	45
Marion	328	297	291	319	313	294	67	5	5	5	10	10	10	2
Marshall	296	279	282	243	266	261	65	40	40	39	43	44	44	9
Maury	736	719	719	699	661	730	143	111	110	107	107	129	132	33
Meigs	124	117	111	133	109	117	18	0	0	1	0	0	1	0
Monroe	413	377	351	407	413	433	92	34	32	35	27	38	41	7
Montgomery	972	921	914	826	872	850	182	496	14	901	-1,677	-514	55	208
Moore	52	50	50	51	50	50	15	1	0	1	-3	-1	0	0
Morgan	200	201	192	194	193	169	49	0	0	0	-1	-1	0	0
Obion	369	360	382	405	384	388	81	32	32	30	32	39	39	12
Overton	278	254	245	282	271	218	66	0	0	0	-1	0	0	0

Source: Population Estimates Program, U.S. Bureau of the Census

County Population Estimates Components of Change: 2000 to 2006

Area	Deaths										International Migration				
	2006	2005	2004	2003	2002	2001	2000*	2006	2005	2004	2003	2002	2001	2000*	
Perry	98	96	102	97	107	83	16	2	2	2	1	2	3	0	
Pickett	57	52	63	68	70	76	18	0	0	0	-1	-1	0	0	
Polk	207	187	190	219	208	175	38	4	4	5	5	6	6	2	
Putnam	644	616	647	659	621	622	137	157	156	144	158	176	178	43	
Rhea	308	320	331	303	303	283	72	11	11	9	12	14	14	2	
Roane	663	634	627	588	595	619	151	25	24	25	22	26	27	7	
Robertson	583	528	550	505	443	495	108	133	130	126	131	151	156	38	
Rutherford	1,301	1,270	1,280	1,179	1,157	1,181	263	364	355	345	334	393	404	113	
Scott	235	243	240	223	193	194	61	4	4	4	3	4	4	0	
Sequatchie	126	100	103	93	96	127	22	8	8	8	7	8	9	2	
Sevier	680	684	747	676	691	631	173	52	51	48	50	60	61	13	
Shelby	7,783	7,587	7,733	7,789	7,864	8,029	1,968	1,851	1,774	1,773	1,579	2,048	2,141	629	
Smith	208	195	198	208	173	194	42	8	8	8	7	8	8	0	
Stewart	135	119	137	146	154	135	44	6	-1	12	-26	-8	0	2	
Sullivan	1,785	1,779	1,888	1,834	1,750	1,757	376	99	96	98	93	119	122	29	
Sumner	1,126	1,146	1,175	1,136	1,090	1,034	229	172	168	169	155	198	203	50	
Tipton	460	460	482	469	481	437	118	24	12	33	-28	4	18	6	
Trousdale	107	102	92	90	82	88	24	8	8	8	10	12	13	2	
Unicoi	224	244	267	248	249	240	52	0	0	1	-1	0	0	0	
Union	183	158	158	162	161	163	37	0	0	1	-1	0	0	0	
Van Buren	69	56	49	59	49	55	6	0	0	0	0	0	0	0	
Warren	423	424	439	407	405	381	89	116	116	109	124	139	139	31	
Washington	1,193	1,169	1,213	1,153	1,145	1,126	268	120	116	115	102	128	133	32	
Wayne	170	181	182	172	174	176	30	4	4	6	7	7	7	0	
Weakley	403	373	332	381	384	363	95	63	63	57	59	76	77	20	
White	323	306	314	328	283	297	66	5	5	5	4	5	5	1	
Williamson	811	742	728	682	687	705	143	246	245	223	246	276	278	70	
Wilson	720	714	779	755	740	705	149	50	48	52	46	62	65	12	

County Population Estimates Components of Change: 2000 to 2006

Area	Internal Migration										Residual				
	2006	2005	2004	2003	2002	2001	2000*	2006	2005	2004	2003	2002	2001	2000*	2000*
TENNESSEE	50,383	40,687	22,724	20,066	11,293	10,461	4,552	70	-3,316	-3,506	-2,444	-1,391	-1,829	140	140
Anderson	878	455	174	193	182	114	-61	-6	-44	-34	-72	-41	-50	5	5
Bedford	644	616	592	494	235	282	108	-6	-25	-36	-12	-21	-24	2	2
Benton	-39	82	-27	50	-18	187	12	3	-10	-8	-15	-13	-9	-2	-2
Bledsoe	105	96	184	91	-3	76	37	1	-7	-9	-10	-10	-7	0	0
Blount	2,329	2,020	1,968	1,561	1,470	1,479	330	-15	-72	-99	-46	-40	-58	2	2
Bradley	944	612	645	102	89	253	84	2	-56	-54	-102	-58	-61	8	8
Campbell	262	52	415	126	87	-104	69	3	-24	-30	-36	-24	-32	1	1
Cannon	132	85	97	84	20	146	90	1	-8	-8	-11	-9	-8	-1	-1
Carroll	140	-217	-11	131	-214	246	13	2	-16	-12	-24	-14	-19	1	1
Carter	254	308	237	1,530	14	181	96	10	-36	-30	42	-41	-40	3	3
Cheatham	268	368	515	25	296	268	148	3	-23	-29	-44	-22	-23	0	0
Chester	106	48	207	-428	54	271	12	0	-10	-12	10	-9	-8	0	0
Claiborne	246	298	221	339	-20	189	50	4	-19	-19	-16	-20	-18	0	0
Clay	29	18	91	11	30	-14	6	2	-4	-7	-7	-6	-7	0	0
Cocke	409	351	249	283	403	101	52	4	-21	-21	-25	-13	-24	3	3
Coffee	522	634	316	382	441	281	80	-1	-32	-28	-34	-20	-33	2	2
Crockett	-66	-27	76	-83	-78	-27	18	3	-9	-7	-17	-9	-11	1	1
Cumberland	1,209	1,103	917	631	1,011	750	238	-22	-32	-49	-11	-10	-28	-8	-8
Davidson¹	-2,609	-3,302	-4,114	-5,826	-9,030	-5,512	-1,680	91	-334	-336	-361	-179	-359	4	4
Decatur	-98	-44	89	-32	-35	67	-14	4	-8	-8	-15	-10	-7	-4	-4
DeKalb	16	92	125	137	99	86	24	5	-12	-12	-11	-9	-13	-1	-1
Dickson	526	318	223	438	302	192	128	-1	-27	-25	-21	-23	-28	0	0
Dyer	-65	195	108	108	-156	-256	29	7	-22	-18	-39	-23	-22	1	1
Fayette	1,585	920	1,175	942	774	1,020	298	-24	-23	-46	29	1	-6	-10	-10
Fentress	326	243	-30	147	163	62	15	-3	-10	-8	-13	-5	-13	0	0
Franklin	434	231	210	220	317	367	46	2	-25	-22	-33	-19	-24	3	3
Gibson	407	167	237	-136	88	-7	-7	-1	-29	-26	-45	-29	-35	2	2
Giles	143	81	-29	-107	-140	147	27	7	-16	-13	-33	-19	-22	2	2
Grainger	256	352	281	268	213	158	54	0	-13	-17	-12	-9	-13	1	1
Greene	617	650	474	441	346	262	84	-1	-39	-43	-41	-33	-41	0	0
Grundy	-50	60	64	39	54	-80	-4	3	-8	-8	-14	-8	-9	1	1
Hamblen	256	329	111	-65	-892	-5	-55	8	-36	-33	-72	-19	-43	5	5
Hamilton	1,068	272	-811	-951	-494	-751	-287	54	-184	-149	-308	-204	-212	26	26

Source: Population Estimates Program, U.S. Bureau of the Census

County Population Estimates Components of Change: 2000 to 2006

Area	Internal Migration							Residual						
	2006	2005	2004	2003	2002	2001	2000*	2006	2005	2004	2003	2002	2001	2000*
Hancock	-42	30	47	-88	-14	35	-4	1	-4	-4	-8	-4	-5	0
Hardeman	34	8	-101	-156	-56	103	11	7	-16	-15	-24	-19	-19	1
Hardin	189	313	-23	46	204	259	19	4	-16	-12	-29	-16	-19	2
Hawkins	522	558	361	419	413	388	109	2	-33	-32	-54	-23	-34	2
Haywood	-103	-216	-46	-82	-341	-62	-2	3	-11	-10	-20	-4	-15	1
Henderson	372	201	196	119	111	38	86	-3	-17	-16	-25	-14	-17	0
Henry	373	268	201	-16	173	129	54	-3	-18	-20	-36	-17	-22	-2
Hickman	63	46	344	50	439	218	130	5	-14	-20	-24	-3	-13	-3
Houston	19	83	-86	65	-28	-15	-61	2	-5	-6	-4	-4	-6	-4
Humphreys	175	125	-3	27	-35	165	-9	0	-11	-9	-19	-12	-10	2
Jackson	-99	-43	-16	37	46	202	47	2	-6	-6	-9	-7	-7	-1
Jefferson	1,027	667	509	987	584	382	252	-11	-29	-33	5	-22	-32	-3
Johnson	0	124	92	189	129	288	18	4	-11	-11	-7	-8	-8	0
Knox	4,718	3,256	1,812	2,093	1,320	1,080	209	12	-3	70	1,262	1,261	1,601	36
Lake	-100	-48	-218	4	-24	56	-6	1	-4	-9	-8	-8	-6	0
Lauderdale	13	-111	-421	-199	-148	-8	-76	5	-14	-21	-23	-17	-23	1
Lawrence	-130	195	-24	-105	379	-102	2	6	-25	-19	-45	-16	-30	4
Lewis	118	-46	-50	30	-11	65	4	0	-7	-6	-10	-9	-10	1
Lincoln	247	354	103	132	149	152	78	0	-20	-16	-31	-18	-20	0
Loudon	1,046	1,129	638	769	740	652	128	-7	-29	-34	-4	-18	-22	-1
McMinn	625	496	300	330	265	447	126	2	-31	-28	-37	-26	-30	2
McNairy	349	224	205	181	-8	-70	45	-1	-16	-16	-20	-17	-16	-1
Macon	117	170	265	102	-86	333	49	5	-14	-17	-18	-12	-11	0
Madison	654	58	-166	-168	-83	201	30	12	-56	-44	-101	-60	-66	11
Marion	232	11	-196	44	-8	-46	-5	2	-16	-16	-27	-20	-21	0
Marshall	468	298	274	4	95	167	75	-1	-18	-17	-34	-15	-19	-1
Maury	1,737	1,240	1,253	1,177	789	147	103	-14	-48	-64	-16	-32	-58	3
Meigs	148	102	106	66	44	66	19	0	-7	-8	-9	-7	-8	-1
Monroe	821	883	840	548	575	365	201	-4	-28	-39	-16	-12	-24	-2
Montgomery	-1,970	4,070	292	2,495	280	-1,256	-153	-1	-90	-67	10	-94	-81	14
Moore	29	47	67	-46	117	67	29	2	-5	-4	-5	-1	-4	-1
Morgan	6	0	-8	21	26	180	31	5	-12	-9	-24	-14	-15	1
Obion	-83	-209	5	-131	-53	-157	14	7	-18	-17	-31	-22	-24	0
Overton	240	49	301	-2	77	18	75	0	-12	-17	-24	-11	-15	0

County Population Estimates Components of Change: 2000 to 2006

Area	Internal Migration										Residual				
	2006	2005	2004	2003	2002	2001	2000*	2006	2005	2004	2003	2002	2001	2000*	2000*
Perry	20	17	-14	87	40	-126	11	1	-4	-3	-2	-3	-4	-1	-1
Pickett	-12	-5	-74	-86	80	86	-1	0	-3	-4	-2	-3	-2	0	0
Polk	-55	69	-200	44	-98	92	36	3	-9	-11	-16	-9	-11	-2	-2
Putnam	1,010	675	558	495	571	320	10	1	-41	-42	-55	-34	-48	3	3
Rhea	341	190	202	312	234	64	42	-1	-19	-18	-14	-13	-21	3	3
Roane	663	175	402	303	288	15	37	-2	-32	-32	-41	-27	-36	3	3
Robertson	1,310	661	531	504	583	751	276	-16	-35	-39	-42	-22	-29	-3	-3
Rutherford	7,973	6,551	5,612	4,174	4,019	3,872	962	-107	-137	-235	8	-50	-99	-8	-8
Scott	0	53	-5	-96	-5	254	38	4	-13	-10	-21	-15	-13	2	2
Sequatchie	279	316	231	174	190	119	38	-2	-8	-12	-5	-4	-6	0	0
Sevier	1,649	1,975	1,403	883	927	1,103	493	-18	-49	-70	-34	-26	-42	-12	-12
Shelby	-2,850	-5,633	-6,684	-5,147	-5,876	-8,130	-1,542	170	-512	-525	-828	-531	-577	57	57
Smith	158	186	70	121	169	113	94	1	-12	-9	-15	-9	-10	-3	-3
Stewart	3	178	-66	69	201	138	94	3	-9	-6	-9	-2	-7	-3	-3
Sullivan	854	683	-335	272	361	-550	-184	13	-90	-71	-157	-88	-100	8	8
Sumner	3,790	2,364	2,288	1,414	1,780	1,720	457	-43	-89	-117	-71	-54	-78	2	2
Tipton	1,122	1,146	294	560	322	950	213	-11	-35	-29	-29	-29	-23	0	0
Trousdale	160	157	44	57	19	32	64	-1	-5	-3	-5	-5	-5	-3	-3
Unicoi	105	14	43	146	150	-5	-9	1	-11	-9	-13	-11	-15	1	1
Union	16	83	-13	169	149	406	47	5	-11	-10	-8	-8	-7	1	1
Van Buren	24	10	-42	-48	56	-43	1	0	-3	-4	-5	-2	-7	0	0
Warren	130	2	35	217	-255	35	50	6	-23	-21	-36	-21	-29	3	3
Washington	1,626	1,359	722	607	1,376	-154	162	0	-70	-65	-98	-41	-82	3	3
Wayne	-20	-7	-22	-95	-22	236	-19	4	-9	-8	-16	-11	-11	-1	-1
Weakley	-259	-38	-455	-213	-167	-619	-8	3	-18	-26	-28	-19	-20	2	2
White	294	373	344	101	85	270	26	0	-14	-20	-21	-13	-14	0	0
Williamson	6,059	5,134	4,234	3,433	2,945	3,141	1,150	-90	-95	-172	33	-23	-69	-22	-22
Wilson	2,994	2,201	1,789	1,522	1,503	1,455	346	-37	-62	-87	-30	-29	-48	2	2

County Population Estimates Components of Change: 2000 to 2006

Area	Group Quarters Estimates							
	2006	2005	2004	2003	2002	2001	2000	
TENNESSEE	152,407	152,407	152,369	152,692	150,840	151,241	147,946	
Anderson	877	877	877	877	877	877	877	
Bedford	513	513	513	513	513	513	513	
Benton	273	273	273	273	273	273	273	
Bledsoe	1,163	1,163	1,163	1,145	1,156	1,147	1,173	
Blount	2,142	2,142	2,142	2,142	2,161	2,131	2,098	
Bradley	2,053	2,053	2,053	2,053	2,280	2,362	2,215	
Campbell	499	499	499	499	499	499	499	
Cannon	165	165	165	165	165	165	165	
Carroll	1,145	1,145	1,145	1,145	1,048	1,056	919	
Carter	3,012	3,012	3,012	3,008	1,525	1,479	1,453	
Cheatham	401	401	401	401	401	401	401	
Chester	948	948	948	948	1,242	1,272	1,121	
Claiborne	647	647	647	647	647	647	647	
Clay	89	89	89	89	89	89	89	
Cocke	364	364	364	364	364	364	364	
Coffee	784	784	784	784	784	784	784	
Crockett	298	298	298	298	298	298	298	
Cumberland	540	540	540	540	540	540	540	
Davidson¹	25,411	25,411	25,411	25,462	24,524	25,493	24,165	
Decatur	230	230	230	230	230	230	230	
DeKalb	315	315	315	315	315	315	315	
Dickson	536	536	536	536	536	536	536	
Dyer	609	609	609	609	609	609	609	
Fayette	392	392	392	392	392	392	392	
Fentress	153	153	153	153	153	153	153	
Franklin	1,864	1,864	1,864	1,864	1,934	1,755	1,660	
Gibson	1,068	1,068	1,068	1,068	1,068	1,068	1,068	
Giles	531	531	531	531	531	527	547	
Grainger	178	178	178	178	178	178	178	
Greene	1,718	1,718	1,718	1,718	1,674	1,574	1,610	
Grundy	205	205	205	205	205	205	205	
Hamblen	790	790	790	790	790	790	790	
Hamilton	8,460	8,460	8,460	8,460	8,581	8,389	7,790	

County Population Estimates Components of Change: 2000 to 2006

Area	Group Quarters Estimates							
	2006	2005	2004	2003	2002	2001	2000	
Hancock	162	162	162	162	162	162	162	
Hardeman	3,935	3,935	3,935	3,909	3,985	3,980	3,964	
Hardin	464	464	464	464	464	464	464	
Hawkins	463	463	463	463	463	463	463	
Haywood	253	253	253	253	253	253	253	
Henderson	352	352	352	352	352	352	352	
Henry	524	524	524	524	524	524	524	
Hickman	1,361	1,361	1,361	1,367	1,392	1,384	1,386	
Houston	190	190	190	190	190	190	190	
Humphreys	233	233	233	233	233	233	233	
Jackson	136	136	136	136	136	136	136	
Jefferson	1,607	1,607	1,607	1,607	1,607	1,607	1,662	
Johnson	1,745	1,745	1,745	1,742	1,678	1,653	1,484	
Knox	12,590	12,590	12,590	12,590	12,437	12,891	12,864	
Lake	2,444	2,444	2,444	2,453	2,461	2,454	2,278	
Lauderdale	2,751	2,751	2,751	2,809	2,794	2,824	2,688	
Lawrence	367	367	367	367	367	367	367	
Lewis	233	233	233	233	233	233	233	
Lincoln	468	468	468	468	468	468	468	
Loudon	433	433	433	433	433	433	433	
McMinn	728	728	728	728	728	716	712	
McNairy	528	528	528	528	528	528	528	
Macon	213	213	213	213	213	213	213	
Madison	3,600	3,600	3,600	3,600	3,697	3,713	3,302	
Marion	249	249	249	249	249	249	249	
Marshall	348	348	348	348	348	348	348	
Maury	1,238	1,238	1,238	1,238	1,238	1,238	1,238	
Meigs	114	114	114	114	114	114	114	
Monroe	597	597	597	597	597	586	546	
Montgomery	4,403	4,403	4,403	4,403	4,253	4,253	4,324	
Moore	112	112	112	112	112	112	112	
Morgan	1,695	1,695	1,695	1,695	1,721	1,713	1,723	
Obion	522	522	522	522	522	522	522	
Overton	177	177	177	177	177	177	177	

County Population Estimates Components of Change: 2000 to 2006

Area	Group Quarters Estimates									
	2006	2005	2004	2003	2002	2001	2000			
Perry	141	141	141	141	141	141	141			
Pickett	70	70	70	70	70	70	70			
Polk	194	194	194	194	194	194	194			
Putnam	2,831	2,831	2,831	2,831	2,794	2,617	2,547			
Rhea	956	956	956	956	956	912	855			
Roane	695	695	695	695	695	695	695			
Robertson	516	516	516	516	516	516	516			
Rutherford	5,884	5,884	5,858	5,867	5,954	5,797	5,772			
Scott	200	200	200	200	200	200	200			
Sequatchie	125	125	125	125	125	125	125			
Sevier	637	637	637	637	637	637	637			
Shelby	19,101	19,101	19,080	19,242	18,994	19,290	18,997			
Smith	148	148	148	148	148	148	148			
Stewart	100	100	100	100	100	100	100			
Sullivan	2,689	2,689	2,689	2,689	2,745	2,799	2,762			
Sumner	1,391	1,391	1,391	1,391	1,391	1,391	1,391			
Tipton	889	889	889	889	889	889	889			
Trousdale	164	164	164	164	164	164	164			
Unicoi	292	292	292	292	292	292	292			
Union	138	138	138	138	138	138	138			
Van Buren	78	78	78	78	78	78	78			
Warren	723	723	723	723	723	723	723			
Washington	3,961	3,961	3,970	4,009	4,170	3,644	4,013			
Wayne	2,304	2,304	2,304	2,344	2,336	2,360	2,167			
Weakley	1,972	1,972	1,972	1,972	2,079	2,098	2,499			
White	305	305	305	305	305	305	305			
Williamson	991	991	991	991	991	991	991			
Wilson	1,304	1,304	1,304	1,304	1,304	1,263	1,148			

U.S. Census Bureau

American FactFinder



Tennessee -- County

GCT-PH1. Population, Housing Units, Area, and Density: 2000

Data Set: Census 2000 Summary File 1 (SF 1) 100-Percent Data

NOTE: For information on confidentiality protection, nonsampling error, definitions, and count corrections see <http://factfinder.census.gov/home/en/datanotes/expsf1u.htm>.

Geographic area	Population	Housing units	Area in square miles			Density per square mile of land area	
			Total area	Water area	Land area	Population	Housing units
Tennessee	5,689,283	2,439,443	42,143.27	926.15	41,217.12	138.0	59.2
COUNTY							
Anderson County	71,330	32,451	344.82	7.31	337.51	211.3	96.1
Bedford County	37,586	14,990	474.83	1.17	473.67	79.4	31.6
Benton County	16,537	8,595	436.20	41.37	394.84	41.9	21.8
Bledsoe County	12,367	5,142	406.71	0.40	406.32	30.4	12.7
Blount County	105,823	47,059	566.65	8.08	558.56	189.5	84.3
Bradley County	87,965	36,820	331.50	2.78	328.72	267.6	112.0
Campbell County	39,854	18,527	498.25	18.19	480.07	83.0	38.6
Cannon County	12,826	5,420	265.71	0.06	265.64	48.3	20.4
Carroll County	29,475	13,057	599.86	0.84	599.02	49.2	21.8
Carter County	56,742	25,920	347.62	6.57	341.05	166.4	76.0
Cheatham County	35,912	13,508	307.13	4.47	302.66	118.7	44.6
Chester County	15,540	6,178	288.74	0.22	288.52	53.9	21.4
Claiborne County	29,862	13,262	441.55	7.27	434.28	68.8	30.5
Clay County	7,976	3,959	259.25	23.14	236.11	33.8	16.8
Cocke County	33,565	15,844	443.15	8.75	434.40	77.3	36.5
Coffee County	48,014	20,746	434.46	5.62	428.84	112.0	48.4
Crockett County	14,532	6,138	265.47	0.21	265.27	54.8	23.1
Cumberland County	46,802	22,442	684.95	3.34	681.61	68.7	32.9
Davidson County	569,891	252,977	526.11	23.85	502.26	1,134.6	503.7
Decatur County	11,731	6,448	344.91	11.01	333.90	35.1	19.3
DeKalb County	17,423	8,409	328.98	24.41	304.57	57.2	27.6
Dickson County	43,156	17,614	491.28	1.42	489.87	88.1	36.0
Dyer County	37,279	16,123	526.48	15.98	510.50	73.0	31.6
Fayette County	28,806	11,214	706.23	1.73	704.50	40.9	15.9
Fentress County	16,625	7,598	498.97	0.33	498.64	33.3	15.2
Franklin County	39,270	16,813	575.77	21.25	554.52	70.8	30.3
Gibson County	48,152	21,059	603.59	0.92	602.67	79.9	34.9
Giles County	29,447	13,113	611.17	0.25	610.93	48.2	21.5
Grainger County	20,659	9,732	302.44	22.11	280.33	73.7	34.7
Greene County	62,909	28,116	624.11	2.42	621.69	101.2	45.2
Grundy County	14,332	6,282	361.14	0.58	360.56	39.7	17.4
Hamblen County	58,128	24,693	175.77	14.74	161.03	361.0	153.3
Hamilton County	307,896	134,692	575.72	33.28	542.44	567.6	248.3
Hancock County	6,786	3,280	223.50	1.21	222.29	30.5	14.8
Hardeman County	28,105	10,694	670.39	2.84	667.55	42.1	16.0
Hardin County	25,578	12,807	596.31	18.45	577.86	44.3	22.2
Hawkins County	53,563	24,416	499.63	12.97	486.66	110.1	50.2
Haywood County	19,797	8,086	534.15	0.95	533.20	37.1	15.2
Henderson County	25,522	11,446	525.91	5.89	520.02	49.1	22.0
Henry County	31,115	15,783	593.45	31.77	561.68	55.4	28.1

Geographic area	Population	Housing units	Area in square miles			Density per square mile of land area	
			Total area	Water area	Land area	Population	Housing units
Hickman County	22,295	8,904	612.70	0.18	612.52	36.4	14.5
Houston County	8,088	3,901	206.92	6.71	200.21	40.4	19.5
Humphreys County	17,929	8,482	556.72	24.50	532.22	33.7	15.9
Jackson County	10,984	5,163	319.56	10.67	308.88	35.6	16.7
Jefferson County	44,294	19,319	314.33	40.51	273.81	161.8	70.6
Johnson County	17,499	7,879	302.73	4.26	298.47	58.6	26.4
Knox County	382,032	171,439	525.78	17.32	508.46	751.3	337.2
Lake County	7,954	2,716	193.79	30.38	163.42	48.7	16.6
Lauderdale County	27,101	10,563	507.14	36.69	470.45	57.6	22.5
Lawrence County	39,926	16,821	617.91	0.74	617.17	64.7	27.3
Lewis County	11,367	4,821	282.48	0.38	282.09	40.3	17.1
Lincoln County	31,340	13,999	570.63	0.39	570.23	55.0	24.5
Loudon County	39,086	17,277	247.31	18.43	228.88	170.8	75.5
McMinn County	49,015	21,626	432.22	1.94	430.28	113.9	50.3
McNairy County	24,653	11,219	560.84	0.79	560.04	44.0	20.0
Macon County	20,386	8,894	307.19	0.06	307.13	66.4	29.0
Madison County	91,837	38,205	558.63	1.63	557.00	164.9	68.6
Marion County	27,776	12,140	512.32	13.96	498.36	55.7	24.4
Marshall County	26,767	11,181	376.10	0.75	375.36	71.3	29.8
Maury County	69,498	28,674	615.52	2.66	612.86	113.4	46.8
Meigs County	11,086	5,188	216.78	21.92	194.86	56.9	26.6
Monroe County	38,961	17,287	652.58	17.67	634.91	61.4	27.2
Montgomery County	134,768	52,167	543.84	4.57	539.28	249.9	96.7
Moore County	5,740	2,515	130.38	1.21	129.18	44.4	19.5
Morgan County	19,757	7,714	522.40	0.35	522.04	37.8	14.8
Obion County	32,450	14,489	555.35	10.43	544.91	59.6	26.6
Overton County	20,118	9,168	434.82	1.43	433.38	46.4	21.2
Perry County	7,631	4,115	422.90	8.00	414.89	18.4	9.9
Pickett County	4,945	2,956	174.58	11.66	162.92	30.4	18.1
Polk County	16,050	7,369	442.35	7.30	435.05	36.9	16.9
Putnam County	62,315	26,916	402.56	1.50	401.05	155.4	67.1
Rhea County	28,400	12,565	336.39	20.45	315.94	89.9	39.8
Roane County	51,910	23,369	394.98	34.00	360.98	143.8	64.7
Robertson County	54,433	20,995	476.67	0.20	476.47	114.2	44.1
Rutherford County	182,023	70,616	623.94	5.03	618.91	294.1	114.1
Scott County	21,127	8,909	533.22	1.13	532.09	39.7	16.7
Sequatchie County	11,370	4,916	266.02	0.18	265.85	42.8	18.5
Sevier County	71,170	37,252	597.73	5.45	592.29	120.2	62.9
Shelby County	897,472	362,954	783.63	29.10	754.53	1,189.4	481.0
Smith County	17,712	7,665	325.35	10.94	314.41	56.3	24.4
Stewart County	12,370	5,977	493.20	34.72	458.48	27.0	13.0
Sullivan County	153,048	69,052	429.69	16.67	413.02	370.6	167.2
Sumner County	130,449	51,657	543.12	13.81	529.30	246.5	97.6
Tipton County	51,271	19,064	474.72	15.35	459.37	111.6	41.5
Trousdale County	7,259	3,095	116.64	2.40	114.24	63.5	27.1
Unicoi County	17,667	8,214	186.49	0.35	186.14	94.9	44.1
Union County	17,808	7,916	247.13	23.57	223.56	79.7	35.4
Van Buren County	5,508	2,453	274.59	1.14	273.46	20.1	9.0
Warren County	38,276	16,689	434.08	1.40	432.69	88.5	38.6
Washington County	107,198	47,779	329.80	3.49	326.31	328.5	146.4
Wayne County	16,842	6,701	735.59	1.63	733.96	22.9	9.1
Weakley County	34,895	14,928	581.81	1.62	580.19	60.1	25.7
White County	23,102	10,191	379.39	2.80	376.58	61.3	27.1
Williamson County	126,638	47,005	583.62	0.94	582.68	217.3	80.7
Wilson County	88,809	34,921	583.20	12.63	570.57	155.6	61.2

(X) Not applicable

Source: U.S. Census Bureau, Census 2000 Summary File 1

STATE OF NORTH CAROLINA
UTILITIES COMMISSION
RALEIGH

DOCKET NO. G-9, SUB 528

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of
Application of Piedmont Natural Gas Company,) ORDER ON ANNUAL
Inc., for Annual Review of Gas Costs Pursuant) REVIEW OF GAS COSTS
to G.S. 62-133.4(c) and Commission Rule)
R1-17(k)(6))

HEARD IN: Commission Hearing Room 2115, Dobbs Building, 430 North Salisbury
Street, Raleigh, North Carolina, on Tuesday, April 10, 2007, at 9:00 a.m.

BEFORE: Commissioner Sam J. Ervin, IV, Presiding; Commissioners Lorinzo L.
Joyner and Edward S. Finley, Jr.

APPEARANCES:

For Piedmont Natural Gas Company, Inc.:

James H. Jeffries IV, Moore & Van Allen PLLC, Bank of America
Corporate Center, 100 N. Tryon Street, Suite 4700, Charlotte, North
Carolina 28202-4003

Brian D. Heslin, Moore & Van Allen PLLC, Bank of America Corporate
Center, 100 N. Tryon Street, Suite 4700, Charlotte, North Carolina 28202-
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For the Using and Consuming Public:

Elizabeth D. Szafran, Staff Attorney, Public Staff – North Carolina Utilities
Commission, 4326 Mail Service Center, Raleigh, North Carolina
27699-4326

Margaret A. Force, Assistant Attorney General, North Carolina
Department of Justice, Post Office Box 629, Raleigh, North Carolina
27602

For Carolina Utility Customers Association, Inc.:

James P. West, West Law Offices, PC, 434 Fayetteville Street Mall, Suite 2325, Raleigh, North Carolina 27601

BY THE COMMISSION: On August 1, 2006, pursuant to G.S. 62-133.4(c) and Commission Rule R1-17(k)(6), Piedmont Natural Gas Company, Inc. (Piedmont or the Company) filed the direct testimony of Keith P. Maust and the direct testimony and exhibits of David R. Carpenter attesting to the prudence of the Company's gas purchasing policies and the accuracy of the Company's gas cost accounting for the twelve-month period ended May 31, 2006.

On August 8, 2006, the Commission issued its Order Scheduling Hearing, Requiring Filing of Testimony, Establishing Discovery Guidelines and Requiring Public Notice. This Order established a hearing date of Tuesday, October 3, 2006; set prefiled testimony filing dates; and required the Company to give notice to its customers of the hearing on this matter.

On August 9, 2006, the Attorney General filed his notice of intervention.

On August 15, 2006, Carolina Utility Customers Association, Inc. (CUCA), filed a petition to intervene, which was granted by the Commission on August 18, 2006.

On September 15, 2006, the Company filed a motion to suspend the procedural schedule as it applied to active parties and to hold the October 3, 2006 hearing for the sole purpose of receiving public testimony.

On September 18, 2006, the Commission issued its Order Granting Motion for Partial Suspension of Hearing Schedule, suspending the dates for filing testimony applicable to active parties, suspending the hearing procedures, and preserving October 3, 2006 for receipt of testimony of public witnesses only.

On October 2, 2006, the Company filed its affidavit of publication.

On October 3, 2006, a hearing was convened for the purpose of receiving public witness testimony. No public witnesses appeared at the hearing.

On February 22, 2007, the Company and the Public Staff filed a Joint Motion to Reestablish Hearing Schedule, requesting that the evidentiary hearing be set for April 10, 2007.

On March 1, 2007, the Commission issued its Order Reestablishing Hearing Schedule which set March 23, 2007, as the filing date for intervenor testimony and April 2, 2007, as the date for filing rebuttal testimony and rescheduled the hearing for Tuesday, April 10, 2007.

On March 23, 2007, the Public Staff filed the direct testimony and exhibits of James G. Hoard, Assistant Director, Accounting Division, and the direct testimony of Thomas W. Farmer, Jr., Director, Economic Research Division, and Richard C. Ross, Public Utilities Engineer, Natural Gas Division.

On April 2, 2007, the Company filed the rebuttal testimony of David R. Carpenter and Bill R. Morris.

No other party filed testimony.

On April 10, 2007, the matter came on for hearing as scheduled and all prefiled testimony and exhibits were admitted into evidence. Company witnesses Keith P. Maust, David R. Carpenter, and Bill R. Morris and Public Staff witnesses Thomas W. Farmer, Jr., Richard C. Ross, and James G. Hoard testified at the hearing.

On May 25, 2007, the Public Staff and the Company filed a Joint Proposed Order, CUCA filed a brief and the Attorney General filed a notice stating that the Attorney General did not assert a position different from the position other parties have submitted in this case and would not, for that reason, file a separate brief or proposed order.

On June 27, 2007, CUCA filed a letter requesting expeditious resolution of the issues in this docket and the issuance of a final order.

Based on the testimony and exhibits received into evidence and the record as a whole, the Commission makes the following:

FINDINGS OF FACT

1. The Company is a public utility as defined in Chapter 62 of the North Carolina General Statutes.

2. The Company is engaged primarily in the business of transporting, distributing and selling natural gas to customers in North Carolina, South Carolina, and Tennessee.

3. The Company has filed with the Commission and submitted to the Public Staff information in the form required by G.S. 62-133.4(c) and Commission Rule R1-17(k); however, the information filed and submitted contains substantial errors and omissions and has required extensive adjustments by the Public Staff.

4. The review period in this proceeding is the twelve months ended May 31, 2006.

5. The Company's gas costs and deferred account balances for the review period were not properly stated. Only after significant adjustments recommended by

Public Staff witness Hoard and agreed to by Company witnesses Morris and Carpenter had been made were the Company's gas costs and deferred account balances for the review period properly stated.

6. During the period of review, the Company incurred total gas costs of \$768,036,403.

7. At May 31, 2006, the Company had a debit balance of (\$40,078,024) in its Sales Customers Only Deferred Account and a credit balance of \$5,080,507 in its All Customers Deferred Account.

8. Piedmont operated a gas cost hedging program on behalf of customers during the applicable review period. Piedmont's hedging activities during the review period were reasonable and prudent.

9. At May 31, 2006, the Company had a credit balance of \$22,251 in its Hedging Deferred Account.

10. It is appropriate for the Company to transfer the \$22,251 credit balance in its Hedging Deferred Account to its Sales Customers Only Deferred Account.

11. It is appropriate that the Company maintain a credit balance of \$40,200 in its NCUC Legal Fund Account.

12. The Company should apply \$243,575 of supplier refunds to the NCUC Legal Fund Account.

13. Since January 2002, the Company has not reported to the Commission refunds it has received from suppliers as required by the Commission's March 12, 1992 order in Docket No. G-100, Sub 57.

14. Beginning with a supplier refund received by the Company in January 2002, the Company has not properly accounted for the refunds it has received from suppliers.

15. The May 31, 2006 balance of the Company's All Customers Deferred Account includes a credit of \$1,238,220 for supplier refunds (including accrued interest).

16. After applying \$243,575 of supplier refunds to the NCUC Legal Fund Account, the Company should have \$1,681,122 of supplier refunds in an escrow account.

17. The Company has committed to filing timely reports of supplier refunds in the format set forth in Hoard Exhibit 5.

18. The Company has agreed to invest the supplier refunds held in escrow accounts in interest-bearing accounts.

19. The Company should file a proposal addressing the disposition of supplier refunds held in escrow not later than sixty days after the date of this Order.

20. The Company follows a number of complex accounting practices that may be unnecessary. The Company has agreed to modify two of these accounting practices: (1) the Company will discontinue its capitalization of storage demand charges, and (2) the Company will record revenues and the cost of gas associated with secondary market transactions in a separate series of non-utility accounts.

21. The Company has agreed to file with the Commission a report that provides the purpose of each monthly cost of gas and deferred account journal entry, an evaluation of whether the journal entry can be simplified or eliminated, and a timeline for implementing appropriate changes.

22. The Company has agreed to file a report that details the components of the October 31, 2006, balance in Account 253.30 – Miscellaneous Deferred Credits.

23. During the review period, the Company failed to file accurate deferred account reports in a timely manner. The Company has committed to filing timely and accurate deferred account reports in the future. In that regard, the Company plans to implement changes in its gas accounting processes that are intended to facilitate its filing of timely and accurate reports.

24. The Company has reflected a credit in its All Customers Deferred Account for Compensation Received for Third Party Facility Damages for the prior review period, pursuant to the Commission's order in Docket No. G-9, Sub 507, and also has reflected a credit in that same deferred account for the amount of similar compensation received during the current review period. The Company should, on an ongoing basis, deduct the cost of gas and volumes associated with third party facilities damage in the determination of its lost and unaccounted for true-up entry.

25. The Company has transportation and storage contracts with interstate pipelines that provide for the transportation of gas to the Company's system and has long term supply contracts with producers, marketers, and other suppliers.

26. The Company utilized a "best cost" gas purchasing policy during the applicable review period consisting of five main components: the price of gas; the security of the gas supply; the flexibility of the gas supply; gas deliverability; and supplier relations.

27. The Company's gas purchasing policy and practices during the review period were prudent and its gas costs during the review period were prudently incurred.

28. The Company should be permitted to recover 100 percent of its prudently incurred gas costs.

29. Pursuant to G.S. 62-133.4(c), Piedmont must refund the May 31, 2006 \$5,080,507 credit balance in its All Customers Deferred Account.

30. Piedmont attributes the shortcomings associated with its gas cost accounting system and related reporting to the use of an inadequate gas cost accounting spreadsheet program, an increasing workload due to acquisitions, the implementation of Sarbanes-Oxley, and the increasing sophistication of the Company's secondary market transactions.

31. Piedmont is taking action that it represents will remedy these gas cost accounting problems.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 1-2

The evidence supporting these findings of fact is contained in the official files and records of the Commission and the testimony of Company witnesses Maust and Carpenter. These findings are essentially informational, procedural or jurisdictional in nature and are based on uncontested evidence.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 3-7

The evidence supporting these findings of fact is contained in the testimony of Company witnesses Carpenter, Morris, and Maust; the testimony of Public Staff witnesses Hoard, Davis, and Farmer; and the provisions of the Commission's Rules.

G.S. 62-133.4 requires that each natural gas utility submit to the Commission information and data for an historical 12-month review period concerning its actual cost of gas, volumes of purchased gas, sales volumes, negotiated sales volumes, and transportation volumes. Commission Rule R1-17(k)(6)(a) establishes May 31, 2006 as the end date of the review period for the Company in this proceeding. Commission Rule R1-17(k)(6)(c) requires the filing by the Company of certain information and data including weather-normalized sales volumes, work papers, and direct testimony and exhibits supporting the information.

Company witness Carpenter testified that the Company filed with the Commission and submitted to the Public Staff a monthly accounting of the computations required by the Commission Rule R1-17(k). Witness Carpenter included the annual data required by Commission Rule R1-17(k)(6)(c) as Exhibit DRC-1 to his direct testimony. Public Staff witness Hoard recommended adjustments to the Company's demand and storage costs, commodity costs, and deferred accounts. These adjustments resulted in changes to Mr. Carpenter's Exhibit DRC-1, which Public Staff witness Hoard incorporated in Hoard Exhibit 1.

With regard to the Company's demand and storage costs, Public Staff witness Hoard testified as follows:

I have increased the Company's demand and storage costs for the Total Carolinas' (North Carolina and South Carolina) operations by \$127,021 to reflect (1) a decrease related to the reclassification of \$109,002 of Columbia Gulf volumetric transportation charges from demand costs to commodity costs, (2) an increase of \$147,955 for Columbia Transmission storage capacity charges that were omitted by the Company, (3) an increase of \$41,069 for Transco FT-NT charges that were omitted by the Company, (4) an increase of \$42,024 related to an error in the amount of capacity release credits, and (5) an increase of \$4,973 for various other small items. The net impact of the adjustments on the North Carolina demand and storage costs (after allocation to the North Carolina operations), as shown on Hoard Exhibit 1, Schedule 2, is an increase in the demand and storage costs by \$95,137 to \$76,158,761.

The Company agreed to witness Hoard's adjustments of demand and storage costs.

With regard to the Company's commodity cost of gas, witness Hoard testified as follows:

I have increased the Total Carolinas' commodity costs shown by the Company on DRC Exhibit 1, Schedule 3, by \$1,563,125 to reflect (1) a \$1,163,196 increase that results from a decrease in the commodity cost of gas assigned to off-system sales, (2) an increase of \$109,002 due to the reclassification of Columbia Gulf volumetric transportation charges from demand charges to commodity costs, (3) a \$144,553 decrease for a credit amount reflected in the Company's JE#17 for November 2005, but not reflected in DRC Exhibit 1, and (4) an increase of \$435,483 to reflect the reclassification of the item described on Line 70 as "Adjustment for Estimates" to Schedule 4 of DRC Exhibit 1. The net impact of the adjustments on the North Carolina commodity cost of gas (after allocation to the North Carolina operations), as shown on Hoard Exhibit 1, Schedule 3, is an increase in the commodity cost of gas by \$1,330,312 to \$738,009,387.

The Company has agreed to witness Hoard's adjustments to the commodity cost of gas.

The Company has agreed to each of the adjustments recommended by witness Hoard. The Company and the Public Staff agree that during the review period Piedmont incurred gas costs of \$768,036,403.

Based on this evidence, the Commission concludes that the Company incurred \$768,036,403 in gas costs during the review period ended May 31, 2006.

Witness Carpenter testified that, as of May 31, 2006, the Company had a debit balance of (\$36,784,602) in its Sales Customers Only Deferred Account and a credit balance of \$3,483,071 in its All Customers Deferred Account.

Witness Hoard testified that the Company's deferred accounts should be adjusted to reflect certain adjustments, including adjustments (1) to recognize transactions reflected in the Company's May 31, 2006 Deferred Account Reports but not reflected in witness Carpenter's Exhibit DRC-1; (2) to reflect differences in the balances carried over from the prior annual review; (3) to correct computational or account posting errors; (4) to reflect the transfer of the hedging account balance approved by the Commission's order in the last annual review to the Sales Customers Only Deferred Account; (5) to correct cash out errors that have accumulated since Piedmont purchased North Carolina Natural Gas Corporation (NCNG) on September 30, 2003; (6) to reflect accrued interest on the NUI Transition Account; (7) to reflect compensation received by the Company for third party damages; (8) to reflect credits for supplier refunds received by the Company; and (9) to reflect the accrued interest effect of recording the correct deferred account entries in the appropriate accounting period. After reflecting these adjustments, witness Hoard determined that, as of May 31, 2006, the Company had a debit balance of (\$40,078,024) in its Sales Customers Only Deferred Account and a credit balance of \$5,080,507 in its All Customers Deferred Account. In response to questions posed by Commissioner Ervin, witness Hoard stated that he was not aware of any further needed adjustments to the deferred account balances.

Company witness Morris, in rebuttal testimony, stated that Piedmont accepts Public Staff witness Hoard's May 31, 2006 deferred account balances. Company witness Morris and Public Staff witness Hoard both testified that, after making the adjustments proposed by the Public Staff and accepted by the Company, the Company's gas costs and deferred account balances for the review period are properly stated.

No other party presented evidence on these issues.

Based on this evidence, the Commission concludes that the Company had a debit balance of (\$40,078,024) in its Sales Customers Only Deferred Account and a credit balance of \$5,080,507 in its All Customers Deferred Account as of May 31, 2006.

The Commission concludes that the Company has filed with the Commission and submitted to the Public Staff information in the form required by G.S. 62-133.4(c) and Commission Rule R1-17(k). This conclusion, however, does not constitute a determination by the Commission that Piedmont properly stated its gas costs and deferred account balances on its books of account during the review period. The Public Staff testified to a number of errors and omissions that it detected during its audit and recommended substantial adjustments. The Company accepted these adjustments. The Commission is disturbed by the number and severity of errors and omissions found by the Public Staff in its audit and will carefully monitor Piedmont's accounting

performance until such time as the Commission is satisfied that similar errors and omissions are unlikely to reoccur.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 8-10

The evidence supporting these findings of fact is contained in the direct testimony of Company witnesses Maust and Carpenter, the rebuttal testimony of Company witness Carpenter, and the testimony of Public Staff witnesses Farmer and Hoard.

In his direct prefiled testimony, Company witness Maust indicated that the Company implemented hedges for the benefit of its customers during the review period consistent with the guidelines contained in the Company's established hedging plan as filed with the Commission. Public Staff witness Farmer testified that he reviewed the Company's testimony and exhibits, data request responses, and various related reports. He noted that in February 2006 NCNG's hedging program was merged with Piedmont's hedging program and that Piedmont operated one combined hedging program subsequent to that date. Witness Farmer testified that the Company's hedging activities were reasonable and prudent.

Company witness Carpenter stated in his direct testimony that the Company had a total debit balance of \$6,476,392 in its Hedging Deferred Account at May 31, 2006. Public Staff witness Hoard testified that the Company's Hedging Deferred Account should be adjusted to reflect certain adjustments, including adjustments (1) to recognize transactions reflected in the Company's May 31, 2006 Deferred Account Reports but not reflected in DRC Exhibit 1; (2) to reflect differences in the balances carried over from the prior annual review; (3) to correct computational or account posting errors; (4) to reflect the transfer of the hedging account balance approved by the Commission's order in the last annual review to the Sales Customers Only Deferred Account; and (5) to reflect the accrued interest effect of recording the correct deferred account entries in the appropriate accounting period. After reflecting these adjustments, witness Hoard determined that, as of May 31, 2006, the correct balance of the Company's Hedging Deferred Account is a credit of \$22,251. Witness Carpenter stated in his rebuttal testimony that Piedmont accepts witness Hoard's May 31, 2006 Hedging Deferred Account credit balance of \$22,251 and recommended that the balance of the Hedging Deferred Account be transferred to the Company's Sales Customers Only Deferred Account. Public Staff witness Farmer agreed that the May 31, 2006 credit balance in the Company's Hedging Deferred Account of \$22,251 should be transferred to the Sales Customers Only Deferred Account.

No other party presented evidence concerning the Company's review period hedging plan or its operations thereunder.

Based on the testimony presented by the Company and the Public Staff, the Commission concludes that the Company's hedging activities during the review period were reasonable and prudent and that the Company's Hedging Deferred Account credit

balance of \$22,251 as of May 31, 2006 should be transferred to the Company's Sales Customers Only Deferred Account.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 11-12

The evidence supporting these findings of fact is contained in the testimony of Company witnesses Carpenter and Morris and Public Staff witness Hoard.

Witness Hoard testified that the Company has not accounted for the NCUC Legal Fund Account in the manner prescribed by the Commission. Witness Hoard stated that the balance reflected on the Company's general ledger account for the NCUC Legal Fund Account has differed significantly from the account balance reported in the monthly Deferred Account Reports filed by the Company with the Commission. The Deferred Account Report reflected a debit balance of \$159,514 as of May 31, 2006, whereas the general ledger reflected a credit balance of \$16,587, a difference of \$176,101. Witness Hoard stated that the difference arose primarily because the monthly Deferred Account Reports have not reflected any reimbursement payments to the Commission since March 1999, or the \$278,856 of supplier refunds that were credited to the general ledger account in May 2006. Witness Hoard testified that the \$278,856 amount recorded by the Company in May 2006 did not correctly reflect the amount of supplier refunds that should have been applied to the account and that this journal entry should be reversed. Witness Hoard testified that he had reviewed the detailed accounting records for the account dating back to March 1993, and has determined that \$243,575 of supplier refunds should be applied to the account.

The Commission addressed the nature and purpose of the NCUC Legal Account in its Order Establishing New Accounting Procedures Under G.S. 62-48(b) issued February 23, 1993, in Docket No. G-100, Sub 57 (Accounting Procedures Order). The Commission required each LDC to establish a separate reserve account for purposes of reimbursing the Commission for expenses incurred pursuant to G.S. 62-48(b) and established a reserve account level for each LDC: \$16,200 for NCNG; \$19,800 for Public Service Company of North Carolina, Inc.; \$22,800 for Piedmont; and \$1,200 for North Carolina Gas Service. Because Piedmont has acquired NCNG and North Carolina Gas Service, the Commission concludes that the current established level for Piedmont should be \$40,200.

Each LDC is required to credit the reserve account directly with supplier refunds up to the level established in the Accounting Procedures Order, charge the reserve account for amounts reimbursed to the Commission, and then credit the account when another supplier refund is received to bring the account back to the established level. The Commission required interest to be accrued on the account in the same manner and at the same rate as for the LDC's other deferred accounts.

Company witness Carpenter testified in rebuttal that the Company agrees with each of witness Hoard's recommendations regarding supplier refunds.

No other party provided evidence on this issue.

Based on the foregoing, the Commission concludes that the Company should apply \$243,575 of supplier refunds to the NCUC Legal Fund Account

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 13-19

The evidence supporting these findings of fact is contained in the testimony of Company witnesses Carpenter and Morris and Public Staff witness Hoard.

All LDCs are required, pursuant to the Commission's Order Regarding Handling of Supplier Refunds by Local Distribution Companies, issued March 12, 1992, in Docket No. G-100, Sub 57 (All LDCs Supplier Refunds Order) to file a report with the Commission that provides details regarding each supplier refund received within one week following the receipt of the refund. In his direct testimony, witness Hoard testified that, since letters dated January 23 and 25, 2002, filed in Docket No. G-100, Sub 57, the Company has not properly reported supplier refunds to the Commission. Witness Hoard recommended that such reports of supplier refunds be made in the format set forth in Hoard Exhibit 5. Company witness Carpenter stated that he agreed with witness Hoard's recommendations.

Witness Hoard testified that he also has determined that, beginning with a refund received in January 2002, the Company has not properly accounted for the refunds it has received from suppliers. Neither the deferred accounts nor the escrow accounts have been properly credited for the supplier refunds that Piedmont has received. He recommended that the All Customers Deferred Account be credited with \$1,238,220 of supplier refunds (including accrued interest) that should have been recorded in the deferred accounts. In addition, he determined that the escrow account balance for Piedmont, as of January 31, 2007, after applying \$243,575 of supplier refunds to the NCUC Legal Reserve Account, should be \$864,009, and that the escrow account balance for NCNG should be \$817,113, for a total of \$1,681,122 for the two accounts. The Company agrees that these balances are correct.

No other party provided evidence on these issues.

Based on the foregoing, the Commission concludes that the Company has not properly reported supplier refunds to the Commission and has not properly accounted for the supplier refunds it has received since January 2002. In addition, the Commission concludes that the Company's periodic reports of supplier refunds should be filed on a timely basis in the format set forth in Hoard Exhibit 5. The Commission further concludes that the All Customers Deferred Account should include a credit of \$1,238,220 for supplier refunds (including accrued interest), as reflected in Finding of Fact No. 7, and that the Company should have a total of \$1,681,122 in supplier refunds in its escrow accounts.

The All LDCs Supplier Refunds Order in Docket No. G-100, Sub 57 required that the refunds held by LDCs in escrow accounts be invested in interest-bearing accounts. Witness Hoard testified that the Company has not invested the amounts held in escrow accounts in interest-bearing accounts. Witness Hoard testified that the Company should maintain a cash or investment account (a balance sheet debit account) that directly offsets each escrow account (a balance sheet credit account). He stated that, typically, supplier refunds should be invested in secure, interest-bearing, short-term securities. Interest earned on the account should then be accrued by offsetting journal entries to the cash/investment account and the escrow account. Essentially, the balance in the cash or investment account should always be the same as the balance of the escrow account. Witness Carpenter stated that he agreed with Mr. Hoard's recommendations.

No other party provided evidence on this matter.

The Commission concludes that Piedmont should invest the supplier refunds held in escrow accounts in interest-bearing accounts in accordance with its agreement.

Except where the Commission has ruled that the refunds should be handled differently, LDC's supplier refunds historically have flowed through to ratepayers. Pursuant to G.S. 62-158, the Commission may order that supplier refunds be set aside for natural gas expansion. Also, supplier refunds may be applied to the NCUC Legal Fund Reserve Account, an account established for the purpose of reimbursing the Commission for expenses incurred pursuant to G.S. 62-48(b).

In its Order Granting Petition Regarding Supplier Refunds issued February 21, 2002, in Docket No. G-9, Sub 459 (Piedmont Supplier Refunds Order), the Commission authorized Piedmont to return supplier refunds to ratepayers by crediting its deferred accounts for supplier refunds that it received. Effective November 1, 2005, the Commission ordered Piedmont in the Order Approving Partial Rate Increase and Requiring Conservation Initiative issued in Docket Nos. G-9, Sub 499, G-21, Sub 461, and G-44, Sub 15 (Rate Case Order) to discontinue depositing the refunds in its deferred accounts and to hold the supplier refunds in an escrow account. NCNG, which was acquired by Piedmont on September 30, 2003, and which was merged into Piedmont on October 31, 2005, had been required by the All LDCs Supplier Refunds Order to hold its supplier refunds in an escrow account since prior to its acquisition by Piedmont.

The Company has been required, since the Rate Case Order became effective on November 1, 2005, to hold all supplier refunds that it receives in an escrow account. Public Staff witness Hoard recommended that the Commission direct the Company to make a proposal in a separate docket that addresses the appropriate disposition of the refunds.

Witness Carpenter agreed that the Company would file a proposal in a separate docket to address the appropriate disposition of the supplier refunds being held by the

Company in the escrow accounts. On cross examination by CUCA, witness Carpenter stated that he was not aware of any expansion projects planned "at this time." He also agreed that the longer the Commission takes to ultimately refund the money to customers, the greater the difference between the identity of the ratepayers who receive the resulting refund and the identity of the ratepayers who bore responsibility for payments to the suppliers from whom the gas was purchased. However, on rebuttal, he stated that the Company would like to review its potential expansion projects before making such a filing.

No other party provided evidence on these issues.

In their Joint Proposed Order, Piedmont and the Public Staff noted that the Company is required to file a biennial report, pursuant to Commission Rule R6-5(11), detailing its plans for providing natural gas in unserved areas of its franchised territory in the near future and suggested that the Company should file its proposal regarding the disposition of supplier refunds held in escrow no later than the October 31, 2007 due date for its biennial natural gas expansion report. However, in light of the delay that has already occurred as a result of the Company's accounting and reporting shortcomings, the Commission requires a more prompt resolution to this issue. The Commission notes that, with previous biennial reports available, the Company will not be starting from scratch and should be able to comply with the filing due date set forth below.

Based on the foregoing, the Commission concludes that the Company should file a proposal regarding the disposition of supplier refunds held in escrow no later than 60 days after the date of this Order.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 20-23

The evidence supporting these findings of fact is contained in the testimony of Company witnesses Carpenter and Morris and Public Staff witness Hoard.

Public Staff witness Hoard testified that, for several years, the Company has not filed accurate and timely deferred account reports. He stated that, in his opinion, the root cause of the recurring problems that Piedmont has experienced with the filing of timely and accurate deferred account reports is that the Company's gas accounting system has not been fully adequate to address the complexities of its changing business practices. The Company also has employed several outdated and, in his opinion, overly complicated accounting practices that have compounded the shortcomings associated with the gas accounting system.

The Commission will first address the accounting practices of the Company that witness Hoard believes to be overly complex. Witness Hoard identified two such accounting practices. The first such practice involves the capitalization and amortization of storage demand charges, and the second involves the accounting treatment of revenues and the cost of gas related to secondary market transactions. Mr. Hoard recommended that the Company discontinue the first practice, and he

recommended that the Company record the secondary market transactions in a series of non-utility accounts, instead of utility accounts. Witness Hoard also recommended that the Company review its gas accounting practices and file a report with the Commission that provides (1) the purpose of each regular monthly cost of gas and deferred account journal entry, (2) an evaluation of whether the journal entry can be simplified or eliminated, and (3) a timeline for implementing any changes. The Company does not oppose these recommendations and no other party provided evidence on these issues.

Based on the foregoing, the Commission concludes that (1) the Company should discontinue the accounting practice of capitalizing storage demand charges and (2) the Company should record revenues and the cost of gas associated with secondary market transactions in a separate series of non-utility accounts. The Commission notes that the Company's fiscal year for financial reporting purposes ends October 31. To permit the Company to make a smooth transition to the new accounting practices, the Commission therefore concludes that the new accounting practices specified herein should be implemented no later than November 1, 2007, at the beginning of the Company's upcoming fiscal year. In addition, the Company should file a report with the Commission that provides the purpose of each monthly cost of gas and deferred account journal entry, an evaluation of whether the journal entry can be simplified or eliminated, and a timeline for implementing appropriate changes. Such a report should be filed within 90 days of the order in this proceeding.

Witness Hoard testified that the Company has not been performing a proper reconciliation of the volumes delivered to the Piedmont system at its receipt points on the interstate pipeline system with the volumes delivered to its customers. In his direct testimony, witness Hoard stated, "In my view, this requires correction and must be addressed as soon as possible." In his discussion of the Company's accounting for customer imbalances, witness Hoard offered three suggested actions. He did not request that the Commission order the Company to take any specific actions.

Witness Hoard's first suggestion addressed the Company's accounting processes. He testified that the interface and communication between the Company's current gas cost accounting system and its other accounting systems, such as the customer accounting system, which contains customer billing data, and the gas costing system, which provides gas purchases details, are in need of extensive improvement. Upon cross-examination, witness Hoard testified that the accounting process changes should be implemented so that changes made to the system result in the most efficient and accurate accounting system. Witness Hoard further testified that the Company should be required to consult with the Public Staff during the development and implementation of changes to its gas accounting system.

In response, Company witness Carpenter testified that Piedmont agrees with many of witness Hoard's conclusions and is actively engaged in the process of revamping its entire gas cost accounting system and in creating processes to address these issues. Witness Carpenter described this revamping process as one that involves

a detailed analysis of the results required from the system, an assessment as to how those requirements can be met, and the development of a new accounting system designed and implemented to satisfy those requirements. Witness Carpenter stated that the Company plans to fully consider and incorporate, to the maximum extent feasible, the accounting system recommendations offered by the Public Staff. Witness Carpenter further testified that Piedmont intends to communicate with the Public Staff should Piedmont conclude that it should not follow one or more of the Public Staff's recommendations and seek the Public Staff's input.

No other parties provided evidence on these issues.

Witness Hoard's second suggestion addressed deferred accounting reports. During the review period, the Company did not file accurate and timely deferred account reports. Furthermore, in response to questions posed by Commissioner Ervin, witness Carpenter testified that, at the time of the hearing, Piedmont was "a couple of months" behind on filing deferred account reports, which, pursuant to Commission Rule R1-17(k)(5)(c), are due 45 days after the end of each monthly reporting period. Witness Carpenter testified that, at the time of the hearing, the February report was due. He testified, "I would assume that we should have that up to date within the next two weeks." Those filings fell outside of the review period. The Commission notes that Piedmont's 2005 deferred account reports were filed in Docket No. G-9, Sub 503 and that the Company's 2006 deferred account reports were filed in Docket No. G-9, Sub 520. Of the seven reports covering the period June through December 2005, four of them were not filed within 45 days after the end of each monthly reporting period as required. There was no record in Docket No. G-9, Sub 503 of Piedmont's advising the Commission that its reports would be late or of any request for an extension of time to file the required reports. Of the five reports covering January through May 2006, three were not filed within 45 days. Again, there was no record in Docket No. G-9, Sub 520 of Piedmont's advising the Commission that its reports would be late or of any request for an extension of time to file the required reports.

The Company has committed to filing timely and accurate reports and, in that regard, the Company has committed to implementing changes in its gas accounting processes that will facilitate its filing of timely and accurate reports. Because the Public Staff has detailed knowledge of the Company's present gas cost accounting process, as well as the regulatory needs of the Commission, the Commission believes that the Company should consult with the Public Staff as the Company seeks to attain the accounting process improvement goals set forth in the testimony of witness Hoard.

As of the end of the review period in this docket, through the extensive efforts of the Public Staff, correct deferred account balances have been established. However, Piedmont is responsible under Commission Rule R1-17(k)(5)(c) for compliance with the Commission's requirements without the necessity for Public Staff assistance. The Commission recognizes that additional efforts will be required to rectify Piedmont's gas cost accounting shortcomings. However, with respect to the monthly deferred account report for September, due in mid-November and thereafter, the Commission requires

Piedmont to submit accurate and timely monthly deferred account reports and will consider taking appropriate action, including the imposition of sanctions, in the event that the Company fails to make accurate and timely deferred account report filings from that date forward.

Witness Hoard's third suggestion addressed the issue of the sufficiency of transaction details pertaining to a specific liability account maintained by the Company, Account 253.30 – Miscellaneous Deferred Credits. Witness Hoard testified that Account 253.30 includes a wide assortment and variety of seemingly unrelated items, such as gas cost expenses, supplier refunds, deferred account entries, and other transactions. Witness Hoard recommended that the Company perform an in-depth analysis of Account 253.30 – Miscellaneous Deferred Credits and file a report with the Commission detailing the components of the account balance as of October 31, 2006. The Company does not oppose this recommendation, and no other party provided evidence on the issue.

Based on the foregoing, the Commission concludes that the Company should file a report that details the components of the October 31, 2006 balance of Account 253.30 – Miscellaneous Deferred Credits within 90 days of the order in this proceeding.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 24

The evidence supporting this finding of fact is contained in the testimony of Public Staff witness Hoard.

Witness Hoard testified that, during the Company's last annual review, he was unable to determine how the Company accounts for compensation it receives for gas lost in connection with certain third party facilities damage or line breaks. As a result, the Commission ordered Piedmont to file a report describing how it accounts for this item. The Company filed the required report on June 12, 2006, in which it indicated that, during the review period ended May 31, 2005, the Company had lost 28,057 dekatherms of gas due to third party damage and had received \$173,792 in related compensation. Witness Hoard testified in this docket that he reflected the \$173,792 amount for the last annual review period as a credit in the current period to the All Customers Deferred Account. Witness Hoard testified that he had also reflected a \$219,836 credit in the All Customers Deferred Account relating to the compensation received by the Company in the current review period. As far as the ongoing accounting procedures for this compensation are concerned, the Company stated in its report that such compensation would be reported as a credit to the cost of gas, and that the volumes of gas lost in connection with third party facilities damage would be tracked and would be included, as a component of gas supply, in the calculation of the lost and unaccounted for true-up journal entry. Witness Hoard testified that, when implemented, this manner of accounting for third party damage would then be consistent with the accounting treatment that the Commission has approved for the same third party facilities damage by Public Service Company of North Carolina, Inc., and that he agreed with Piedmont's proposed accounting treatment for such damage.

No other party presented evidence on this issue.

Based on the foregoing, the Commission concludes that the Company's proposed accounting treatment for compensation received in connection with third party facilities damage is appropriate and should be approved.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 25-28

The evidence supporting these findings of fact is contained in the testimony of Company witness Maust and Public Staff witness Ross.

Company witness Maust testified that the Company's gas purchasing policy is appropriately described as a "best cost" policy. This policy consists of five main components: price of gas, security of gas supply, flexibility of gas supply, gas deliverability, and supplier relations. Witness Maust stated that all of these components are interrelated and that the Company considers and weighs each of these five factors in establishing its entire supply portfolio.

Witness Maust further testified that the Company purchases gas supplies under a diverse portfolio of contractual arrangements through the spot market and through long-term contracts. Long-term gas supplies are purchased under contracts ranging in term duration from one year (or less) to terms extending through October 2009. Spot gas contracts provide for little or no supply security because they are interruptible and short-term in nature. Long-term firm supplies are usually more expensive; however, they are also the most reliable and most secure source of gas. Some of the Company's firm contracts are for winter service only and some provide for 365-day (annual) service.

Witness Maust described how the interrelationship of the five factors affects the Company's construction of its gas supply portfolio under its best cost policy. The long-term contracts, supplemented by long-term peaking services and storage, generally are aligned with the firm market; the short-term spot gas purchases generally serve the interruptible market. In order to weigh and consider the five factors, the Company must keep itself informed about all aspects of the natural gas industry. The Company, therefore, stays abreast of current issues by intervening in all major Federal Energy Regulatory Commission (FERC) proceedings affecting pipeline suppliers, maintaining constant contact with existing and potential suppliers, monitoring gas prices on a real-time basis, attending conferences, and subscribing to industry literature.

Witness Maust stated that the Company's greatest challenge in applying its best cost policy is in dealing with future uncertainties in a dynamic national and regional energy market. Future demand for gas is affected by economic conditions, customer conservation efforts, weather patterns, regulatory policies, and energy industry restructuring efforts. Future availability and pricing of gas supplies are affected by overall demand, oil and gas exploration and development, pipeline expansion projects, and regulatory policies and approvals. Witness Maust further stated that the Company

did not make any changes in its best cost gas purchasing policies or practices during the test period.

Witness Maust also indicated that, during the past year, the Company has taken several additional steps to manage its costs, including actively participating in proceedings at the FERC and other regulatory agencies that could reasonably be expected to affect the Company's rates and services, actively renegotiating and restructuring its supply arrangements when possible, promoting more efficient use of its system, and utilizing the flexibility within its existing supply and capacity contracts to purchase and dispatch gas and release capacity in the most cost effective manner.

Public Staff witness Ross testified that he had reviewed the Company's gas supply, transportation and demand contracts, as well as the Company's data request responses related to the Company's gas purchasing philosophies, customer requirements, and gas portfolio mixes. Based on this review, witness Ross testified that the Company's review period gas costs were prudently incurred.

No other party presented evidence on these matters.

Based on the foregoing, the Commission concludes that the Company's gas purchasing policies and practices during the review period were prudent and that its gas costs during the review period were prudently incurred and should be recovered.

EVIDENCE AND CONCLUSIONS FOR FINDING OF FACT NO. 29

The evidence supporting this finding of fact is contained in the testimony of Company witness Carpenter and Public Staff witnesses Ross and Hoard. No other party presented evidence on this issue.

The time required to complete the investigation and hearing for this annual review proceeding has been much longer than it should have been. Piedmont's annual review period covers a 12-month period ending May 31 of each year, and the hearing for Piedmont is ordinarily held on the first Tuesday of October. See Commission Rule R1-17(k)(6). In this proceeding, the Commission originally scheduled a hearing for October 3, 2006; however, on September 15, 2006, Piedmont filed a motion to suspend the hearing schedule "in order to permit outstanding and unresolved accounting issues between Piedmont and the Public Staff to be resolved prior to the filing of intervenor testimony and the evidentiary hearing." The Commission issued an order on September 18, 2006, granting that motion. Subsequently, on February 22, 2007, Piedmont and the Public Staff filed a joint motion to reestablish the hearing schedule, and the Commission issued an order on March 1, 2007, setting a new date for the filing of intervenor testimony and scheduling the hearing that it held on April 10, 2007. Therefore, in this proceeding, fourteen months have passed from the end of the review period to the date on which the Commission issues this order.

In pre-filed testimony, Piedmont witness Carpenter proposed to change rates to recover or refund the balances in the Company's deferred accounts.

Public Staff witness Ross testified that, in light of the adjustments to the deferred accounts recommended by Public Staff witness Hoard and in light of the passage of time since Piedmont's testimony was pre-filed, the current deferred account balances are different from those originally filed. Witness Ross stated that the best approach would be for Piedmont to make all of witness Hoard's recommended deferred account adjustments and, in a subsequent purchased gas adjustment or other appropriate proceeding, to implement such temporary rate increments or decrements as are then appropriate.

Witness Carpenter stated in his rebuttal testimony that he agreed with witness Ross. Witness Carpenter further stated that the goal of approving increments and decrements is to refund or surcharge customers, as appropriate, for balances remaining in the Company's deferred accounts at the end of the review period. Those balances vary from month-to-month, sometimes substantially, and, in this case, the passage of a complete winter heating season since the end of the review period makes the end-of-period balances much less useful in establishing meaningful rate adjustments. Witness Carpenter recommended holding any increment or decrement in abeyance at this time.

Under cross-examination by CUCA, witness Carpenter stated that he was unaware of any temporaries relating to the All-Customers Deferred Account. He further agreed that the \$5 million balance identified by witness Hoard as being owed to the ratepayers as of May 31, 2006, would not be given back to ratepayers until a rate decrement is approved. Carpenter added that the balances in the deferred accounts are rolling balances and that the test period "is now quite a ways in the rear-view mirror." On redirect, witness Carpenter testified that he did not have updated information on the balance in the All-Customers Deferred Account since September 2006; however, customers owed Piedmont \$2 million as of the end of September.

In their Joint Proposed Order, Piedmont and the Public Staff maintained that, while G.S. 62-133.4(c) anticipates that credit balances in a gas utility's deferred accounts will be refunded to customers, this subsection does not provide a specific timetable for such refunds. These parties proposed that the Commission postpone any rate changes until a future purchased gas adjustment or until after the next annual review proceeding.

In its post-hearing brief, CUCA noted that, with the corrections proposed by the Public Staff, the balance in Piedmont's All Customers Deferred Account at the end of the test period exceeded \$5 million owed to customers. CUCA argued that G.S. 62-133.4(c) mandates that over-recoveries be refunded and that the Public Staff, by not recommending an immediate refund, was "gaming the system and manipulating rates in a manner that unfairly and unlawfully favors residential customers by taking advantage of seasonal usage variations and preventing industrial customers from receiving the full benefit to which they are entitled." Finally, CUCA argued that "the longer the Commission waits to refund the money to ratepayers, the greater the difference will be

between the pool of recipient ratepayers and the pool of ratepayers who originally overpaid for their gas service."

The Commission concludes that steps must be taken in this docket to refund any outstanding over-recovery. G.S. 62-133.4(c) provides in relevant part:

The Commission, upon notice and hearing, shall compare the utility's prudently incurred costs with costs recovered from all the utility's customers that it served during the test period. If those prudently incurred costs are greater or less than the recovered costs, the Commission shall, subject to G.S. 62-158, require the utility to refund any overrecovery by credit to bill or through a decrement in its rates and shall permit the utility to recover any deficiency through an increment in its rates.

The Commission recognizes that the deferred account balances are ever-changing, rolling balances. The Commission likewise recognizes that, in this case, significant time has passed since the end of the review period and that the balances in Piedmont's deferred accounts are no longer what they were at the end of the test period on May 31, 2006. Nevertheless, the Commission concludes that the mandatory language of the statute requires a refund to ratepayers in this docket. Moreover, the significant passage of time since the end of the review period results from deficient gas cost accounting practices of Piedmont, practices for which ratepayers bear no responsibility.

The Commission addressed this issue shortly after enactment of G.S. 62-133.4. In a 1993 prudency review conducted in Docket No. G-5, Sub 318, a \$1.6 million balance was due to PSNC in its Sales Customers Deferred Account and a \$2.6 million balance was due to customers in the All Customers Deferred Account. In its October 21, 1993 Order in that proceeding, the Commission concluded:

Following the hearing, the Public Staff reconsidered its position in this matter and concluded that G.S. 62-133.4(c) is more appropriately interpreted to require that rates be decreased when an overcollection occurs.....

CUCA filed a post-hearing brief in which it argues that under G.S. 62-133.4(c) the Commission must make rate adjustments in each annual gas cost review proceeding "to recoup any test period underrecovery and to disgorge any test period overrecovery." In making this argument, CUCA stresses that the statute uses the word "shall" as to both the refund of any overrecovery and the recovery of any deficiency. The Commission rejects CUCA's argument. CUCA ignores the words that follow "shall." The statute provides that the Commission shall "require" the utility to refund any overrecovery, but it provides that the Commission shall "permit" the utility to recover any deficiency. The term "require" means to direct, demand or compel while the term "permit" means to allow or

consent, to give leave. Black's Law Dictionary 1140 and 1340 (6th ed. 1990). In this proceeding, Public Service has not asked to recover the undercollection in the deferred account for sales only customers, and the statute does not require the Commission to order such.

In Sub 318 the Commission did not approve a rate increment to recover the undercollection in the Sales Only Deferred Account because PSNC had not proposed one. However, the Commission did require a rate decrement to refund the \$2.6 million overrecovery in the All Customers Deferred Account because the statute required it.¹

Piedmont and the Public Staff argue in this proceeding that the Commission could delay implementation of any decrement because the statute does not set a time limit for implementation. The Commission disagrees. The statute requires the utility to refund any overrecovery by credit or rate decrement, and the Commission concludes that such refund must be ordered when an overrecovery exists and when any party insists that a refund be made, as CUCA has requested in this case. The Commission notes that the statute does, however, allow for a rate decrement to refund an overrecovery, which means that the overrecovery may be refunded over time, rather than by an immediate, one-time credit. As a result, the Commission will order a decrement as advocated by CUCA.

The Commission finds no support for CUCA's contention that the Public Staff is "gaming the system" to favor residential customers. Although the Commission does not agree with the legal position advanced by the Public Staff in opposition to the result that we reach with respect to this issue, we find no basis for concluding that the Public Staff urged us to refrain from ordering the implementation of a decrement for the purpose of favoring one customer class over another. As a result, this CUCA argument does not provide any basis for our decision whatsoever.

Witness Hoard testified that, as of the end of the review period in this docket (May 31, 2006) and with his adjustments, a credit balance of \$5,080,507 exists in the Piedmont All Customers Deferred Account and that a debit balance of \$40,078,024 exists in the Sales Customers Only Deferred Account. In response to questions posed by Commissioner Ervin, witness Hoard testified that he was unaware of any additional work that would be needed to adjust the test period deferred account balances and that he was satisfied that the balances as of the end of the review period, as adjusted, had been properly stated.

The Commission therefore orders a decrement in Piedmont's rates to refund the credit balance in its All Customers Deferred Account as of May 31, 2006. The

¹ The Commission notes that the Sub 318 Order simultaneously approved an offsetting rate increment, resulting in no effective rate change. PSNC had requested such an offset in its testimony "in order to avoid changing billing rates to implement changes of such small magnitude," and the Public Staff supported such an offset in Sub 318 because the All Customers Deferred Account balance was "relatively low" at the end of the test period and went negative thereafter. In this docket, unlike Sub 318, no request for an offset has been made. On the contrary, Piedmont and the Public Staff recommend a delay in implementing a decrement rather than seeking approval of an offsetting rate change.

Commission will allow Piedmont two weeks from the date of this order to calculate and file an appropriate proposed rate decrement for Commission approval.

EVIDENCE AND CONCLUSIONS FOR FINDINGS OF FACT NOS. 30 AND 31

The evidence supporting these findings of fact is contained in the testimony of Company witnesses Carpenter and Morris and Public Staff witness Hoard.

The Commission is seriously concerned by the shortcomings in Piedmont's gas cost accounting system and practices, which were described at length in the Public Staff's and the Company's testimony in this docket. The deficiencies in the Company's gas cost accounting system and practices include obtuse gas accounting practices, which confuse even those who designed and used that system; omissions; errors; and failures to follow Commission orders.

Company witness Morris, in his rebuttal testimony, stated that "it is not uncommon for the Public Staff to detect and correct these types of errors in prudence review proceedings." He testified additionally, however, that "I think what may be unusual about this year is the scope and depth of the Public Staff's investigation, which likely led to a greater number of these types of adjustments." Company witness Carpenter testified that, in previous annual reviews, the Commission has always found that the Company's gas costs "as adjusted" were properly accounted for. In Finding of Fact 5 in the Commission's April 4, 2006 Order on Annual Review of Gas Costs in Docket No. G-9, Sub 507, the Commission explicitly stated that, "After making nine deferred account adjustments recommended by Public Staff witness Hoard and agreed to by Company witness Boggs, the Company has properly accounted for its gas costs incurred during the review period."

Commissioner Joyner questioned Public Staff witness Hoard on why accounting problems have come up repeatedly. Witness Hoard testified that, in the past, when the Public Staff pointed out deficiencies, the Company had taken a "band-aid" approach. He added that the people involved did not want to change the system they had in place and that they continued to do things the same way, "adding more layers on top." Witness Hoard testified that the situation had "gotten worse" over time.

Piedmont witness Carpenter also addressed the roots of the shortcomings in the Company's gas accounting. In his rebuttal testimony, he stated that "until last year, Piedmont's gas cost accounting function was supervised and directed under Piedmont's accounting department with no direct report responsibility to the personnel working in rates and regulatory affairs." He added that, historically, the gas accounting function was performed by one primary person with assistance from several other accountants utilizing a spreadsheet system developed within the Company. He asserted, "For many years this system did work," although he acknowledged that "it was not perfect and mistakes were made in how individual gas costs were recorded and reported." Mr. Carpenter testified that the Company tried to modify its spreadsheet system to address concerns raised by the Public Staff, but that the changes "may have even made the

situation more problematic because they ultimately complicated the manner in which Piedmont's accountants reported gas costs to the Commission and reconciled those costs to the Company's financial statements."

In discussing the various accounting issues identified by the Public Staff, Piedmont witness Carpenter listed four causes for the problems in question. He stated that the amount and the complexity of the work involved with the Company's gas cost accounting function was effectively multiplied by a factor of two or three by the Company's acquisitions of NUI Corporation, NCNG, and Eastern North Carolina Natural Gas in recent years. Witness Carpenter added that the workload of Piedmont's accounting personnel was also increased by the passage of the Sarbanes-Oxley Act. He further stated that the level and sophistication of Piedmont's secondary market activities, which are handled by the gas accounting system, has dramatically increased over the last several years. Finally, he stated that the Company began to see evidence that the gas cost accounting spreadsheet system and the management structure that had been used for many years were "not fully adequate to efficiently manage, track, and report gas costs under the circumstances."

On cross examination by CUCA, Company witness Carpenter testified that Piedmont did "incorporate some of the NCNG people into our corporate office." However, he further stated that some NCNG accountants who were offered positions did not come to Charlotte "because they preferred their lifestyle and their location." In addition, witness Carpenter was asked by counsel for CUCA, "Why did it take Piedmont more than almost eight months to get to the point where you are implementing changes to make the kinds of corrections in his adjustments made back in the fall of 2006?" Mr. Carpenter's response was that as part of a reorganization, Piedmont had made a lot of significant changes last July 1 and "quite a fair number of people who had experience either left the Company or moved to different positions." He added, "When we re-staffed the Gas Cost Accounting Department, as I mentioned, it is difficult to find people with the proper background and knowledge to fill those positions. So quite honestly, we were running fairly shorthanded through the fall period."

On cross examination by Piedmont, witness Hoard testified that his adjustments to the All Customers Deferred Account included adjustments that benefited the customers and the Company. Witness Hoard also agreed that he had worked with Piedmont and its gas accounting system for many years and has been familiar with the personnel involved with the system for ten to fifteen years. When asked if he had any reason to believe that the mis-accounting of supplier refunds was an effort to divert or confiscate funds for the benefit of the Company he replied, "No, I don't."

Company witness Carpenter testified that over a period of years, Piedmont had taken several steps to address the problem. However, the resources applied did not produce the results needed. Witness Carpenter stated that the Company had "some unfortunate failures" in terms of personnel brought in. He stated that the Company has had "a couple of stop and starts with some personnel moves."

Mr. Carpenter testified that, as part of the reorganization last year, he and the Piedmont comptroller sat down with upper management and ascertained that the Company had a real need to greatly improve the processes of month-end closing and gas cost accounting. He stated that they were able to convince upper management that "this is the number one priority."

Mr. Carpenter further testified that, as part of Piedmont's overall restructuring, the Company brought the gas accounting under the direct responsibility of the regulatory affairs department, which he heads as the Managing Director of Regulatory Affairs. He, in turn, reports to Mr. Frank Yoho, the Senior Vice President of Commercial Operations. However, witness Carpenter testified that with regard to the gas accounting issues, he was "in reality, reporting to a team of Tom Skains, CEO; David [Dzuricky], CFO and Frank Yoho." Mr. Carpenter stated that Piedmont now feels it is more appropriate to have gas accounting report to the Regulatory Affairs area because "most of the things in gas cost accounting are driven by the regulation by the three states."

A Manager of Gas Cost Accounting who had previous gas cost accounting experience with PSNC was hired "a month ago," along with four new gas cost accountants, giving the Company a total of five gas cost accountants and one manager. Witness Carpenter stated that the Company was using these resources as well as those of the Public Staff and other LDCs to address the cost accounting issues. In response to questions posed by Commissioner Ervin, witness Carpenter stated that the Company had not conducted any studies to determine the appropriate staffing level for its accounting function other than having discussions with PSNC. He stated that Piedmont, through its knowledge of the task and responsibilities, had come up internally with what the Company thinks is a appropriate level of staffing

Witness Carpenter further testified that Piedmont has also engaged a consulting firm, KP&G, "to review the entire financial end-of-month closing process with special emphasis being placed on the gas cost accounting function." That firm was scheduled to present recommendations "within six weeks and implementation of improvements will follow."

Witness Carpenter, when asked "How significant were the issues relating to Piedmont's gas cost accounting practices?" in his rebuttal testimony, replied "I think it depends on your perspective." He added, "From the customers' perspective, the impacts were largely buffeted by both the Public Staff's efforts to ensure accurate reporting and the method by which gas costs are passed through to customers." When asked if he was aware of any direct harm to customers that has resulted from Piedmont's accounting issues, he responded, "No." On cross examination by CUCA, witness Carpenter agreed that none of the roughly \$5 million identified by witness Hoard had been returned to customers and none would be until a decrement was put in place. He further agreed that the longer the Commission waits to refund the money to customers, the greater would be the difference between the identity of those who paid the original gas costs in rates and those who receive the benefit of any future gas cost-related rate reductions.

Witness Carpenter stated that the Company was still two months behind on filing its deferred account reports. Witness Carpenter apologized for the failure to comply with Commission orders and stated, "You have my word that we will do that in the future."

In his rebuttal testimony, Company witness Carpenter stated that he did not believe that the Commission should formally order Piedmont to adopt Public Staff witness Hoard's recommendations. He stated, "We believe that the design and operation of the Company's accounting system is the primary and fundamental responsibility of Piedmont and its management." Chairman Finley, Commissioner Ervin and CUCA all questioned witness Hoard about whether the Commission should order changes in Piedmont's accounting system, including those suggested by the Public Staff. Witness Hoard testified that he thought that Piedmont should take the Public Staff's recommendations into account, but the Public Staff did not seek ordering paragraphs requiring Piedmont to adopt Mr. Hoard's suggestions.

No other party presented evidence on these issues.

The Commission determines that Piedmont should address and rectify the deficiencies and other problems outlined in detail above. These deficiencies have existed for some time, and the Public Staff's extensive audit in this docket has only served to bring them fully to the Commission's attention. Although the Commission commends the Public Staff for its efforts in correcting these accounting deficiencies and errors, the Public Staff's efforts should never have been necessary. If nothing else, the nine adjustments addressed in Sub 507 should have alerted Piedmont to the extent of the shortcomings in its gas cost accounting practices and should have led the Company to take corrective action without the necessity for Public Staff or Commission intervention. In this order, the Commission has explicitly found in accordance with the uncontradicted testimony that Piedmont's gas costs were not properly accounted for and that only through the extensive and time-consuming efforts of the Public Staff has a proper accounting been achieved. The Commission trusts that this finding will be sufficient to spur Piedmont to make any additional improvements necessary to ensure that the Company's gas costs are appropriately accounted for and that all reports required by the Commission are accurately prepared and submitted in a timely manner.

The various factors to which Piedmont witness Carpenter attributed the Company's gas cost accounting difficulties should not have resulted in the problems that have been revealed in this proceeding. The Company has an obligation to ensure that its staff is of sufficient size and possesses sufficient knowledge and skill to comply with its regulatory obligations. With regard to Piedmont's three acquisitions, Piedmont bears responsibility for completing the acquisitions while still fulfilling its responsibility to maintain and accurately report gas accounting information in a timely manner. Similarly, Piedmont must act to comply with the Sarbanes-Oxley Act while still fulfilling its responsibility to the Commission to maintain and report gas accounting information as required by statute, regulation, and Commission orders. The 25% of the net

compensation associated with secondary market transactions that Piedmont is allowed to retain under the Commission's Order on Stipulation in Docket No. G-100, Sub 67 was intended to compensate local distribution companies for the additional time and expense involved in active participation in the secondary market as well as incenting such participation.² Finally, the fact that the Company began noting deficiencies in its ability to adequately account for and report gas cost information should have been a spur to improvement and does not constitute an adequate explanation for the problems that have been disclosed in this proceeding.

The Commission is particularly concerned by the Company's failure to comply with various provisions of earlier Commission orders. The Commission attempts to have valid reasons for ordering regulated utilities to act in a certain manner and expects those orders to be obeyed. Although the Commission understands that utilities have the right to challenge our orders on appeal or in other appropriate ways in order to protect their legal rights, simple non-compliance with such orders is not a valid option. The level of unexplained non-compliance with prior Commission orders revealed by the present record is troubling and will be taken into account in the event of any further non-compliance with such orders in the future.

Piedmont's failures in gas accounting put the Company's customers at risk. According to G.S. 62-33 and G.S. 62-34, the Commission has a responsibility to keep informed about the activities of the utilities subject to its jurisdiction and to investigate the books and records maintained by regulated entities. The relationship between the deficiencies in Piedmont's gas cost accounting and the Commission's ability to protect consumers through the exercise of these statutory powers should be obvious. The Company's failure to render timely and accurate gas cost accounting reports strikes at the heart of this Commission's ability to effectively oversee Piedmont's activities. The record in this proceeding demonstrates that Piedmont, over an extended period of time, has failed to adequately account for its gas costs and to comply with Commission filing requirements in a timely and adequate manner. Such deficiencies in the accounting information provided in accordance with North Carolina law hamper the Commission's ability to set rates that are fair and equitable to both customers and stockholders and to limit inappropriate fluctuations in the utility's rates.

While the Commission attempts to grant reasonable requests for extensions of time, Piedmont on too many occasions has simply chosen to ignore deadlines for filing reports without even attempting to request additional time to make the required filings, thus making it even more difficult for the Commission to carry out its regulatory duties. As a result, the Company's failure to account for and report its gas costs in an accurate and timely manner have put customers at risk.

² The Order on Stipulation stated, "The Commission recognizes, as noted in the comments of the LDCs, that this sharing ratio must serve two functions: it must compensate the LDCs for the additional administrative burden and operational complexities that can be attendant to negotiating and administering secondary market transactions, and it must provide an adequate incentive for LDCs to actively seek such transactions." The Commission notes that Piedmont retained approximately \$8.4 million in net secondary market compensation in the review period and yet failed to properly account for its gas costs.

A public utility's management bears responsibility for conducting the business of the utility. In carrying out this responsibility, management is fulfilling its responsibilities to both its own shareholders and to the Commission. However, without adequate accounting systems and capabilities, management lacks the necessary tools to adequately perform either function. In the event that a utility fails to appropriately keep track of its costs, it cannot propose legally sufficient rates. Furthermore, a persistent failure to comply with a regulatory agency's reporting rules can result in the assessment of a rate of return penalty or other sanctions, a result that would not be beneficial to shareholders. Thus, the Company's failure to adequately account for and report its gas costs in an accurate and timely manner could have adverse implications for shareholders as well.

No party has requested the imposition of penalties or sanctions in this proceeding. No party has requested that the Commission order Piedmont to employ the changes in the gas cost accounting practices presented by the Public Staff. The Commission is reluctant at this juncture to order the implementation of remedies that no party has proposed. Piedmont has been commendably forthright in acknowledging the deficiencies described above and has assured the Commission that these deficiencies will be promptly and adequately remedied. The Commission accepts Piedmont's assurances that it will remedy the conditions that led to the existing problems and relies on Piedmont's representations that these problems will be satisfactorily addressed in not imposing sanctions on Piedmont at this time. The accounting problems at issue in this proceeding can only be resolved through concerted efforts by relevant Piedmont personnel with complete support from upper management. However, while witness Carpenter testified that he had convinced upper management that "this is the number one priority," no member of Piedmont's upper management appeared before the Commission to testify in this docket or attended the hearing. The Commission expects Piedmont's upper management to ensure that the accounting issues revealed by the present record will be adequately addressed and will take appropriate action in future proceedings in the event that this fails to occur.

IT IS, THEREFORE, ORDERED as follows:

1. That the Company's accounting for gas costs during the twelve-month period ended May 31, 2006, under review in this proceeding, as adjusted by the Public Staff, is approved;
2. That the Company is authorized to recover 100% of its gas costs incurred during the period of review covered in this proceeding;
3. That the Company shall, within two weeks from the date of this order, file proposed tariffs implementing a decrement to rates sufficient to return the balance in the All Customers Deferred Account as of the end of the review period to customers over the course of the next twelve months;

4. That the Company shall file a proposal by October 31, 2007 in a separate docket that addresses the appropriate disposition of the supplier refunds held in escrow accounts;

5. That the Company shall file timely reports of supplier refunds. Such reports, which are due within one week following the receipt of the refund, shall be filed in the format set forth in Hoard Exhibit 5;

6. That the Company shall invest the supplier refunds held in escrow accounts in interest-bearing accounts;

7. That the Company shall discontinue its accounting practice whereby it capitalizes storage demand charges, effective no later than November 1, 2007;

8. That the Company shall change its accounting practices for secondary market transactions such that its accounting records will reflect the revenues and the cost of gas associated with secondary market transactions in a separate series of non-utility accounts, effective no later than November 1, 2007;

9. That the Company shall file a report that provides the purpose of each monthly cost of gas and deferred account journal entry, an evaluation of whether the journal entry can be simplified or eliminated, and a timeline for implementing appropriate changes within 90 days of this Order;

10. That the Company shall consult with the Public Staff to attain the accounting process improvement goals set forth in the testimony of Public Staff witness Hoard;

11. That the Company shall file a report that details the components of the October 31, 2006 balance of Account 253.30 – Miscellaneous Deferred Credits within 90 days of this Order; and

12. That the Company will rectify the gas cost accounting deficiencies and shortcomings addressed above forthwith and that the Company shall file reports in compliance with Commission requirements in an accurate manner and on a timely basis henceforth.

ISSUED BY ORDER OF THE COMMISSION.

This the 1st day of August, 2007.

NORTH CAROLINA UTILITIES COMMISSION

Gail L. Mount

Gail L. Mount, Deputy Clerk



American Gas Association

Energy Analysis

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EA 2003-01

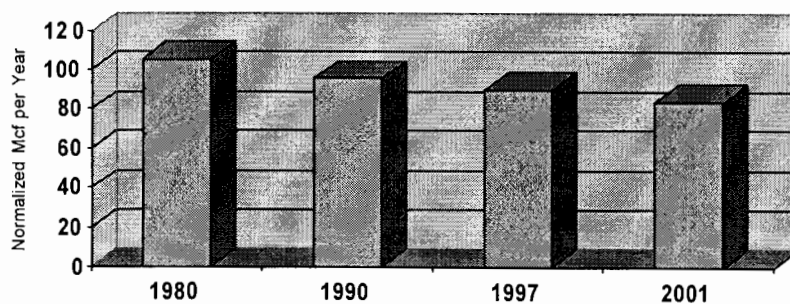
June 16, 2003

PATTERNS IN RESIDENTIAL NATURAL GAS CONSUMPTION, 1997-2001

I. Introduction

This analysis concludes that natural gas use per residential customer dropped by 6.4 percent from 1997 through 2001. This reduction per customer is in addition to a 16 percent reduction observed from 1980 through 1997. Nationally, natural gas use per residential customer was 106 thousand cubic feet (Mcf) per year in 1980, 89 Mcf per year in 1997, and 83 Mcf per year in 2001 (Chart 1). A previous AGA analysis¹ quantified the primary factors contributing to this decline on both a national and a regional basis and those same factors are again analyzed herein for the more recent period. It should be noted that all data in these analyses have been adjusted to reflect normal weather.

Chart 1
Use Per Residential Customer

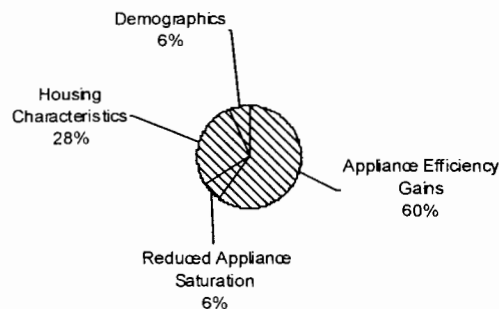


¹ *Patterns in Residential Natural Gas Consumption Since 1980*, American Gas Association, February 2000

II. Executive Summary

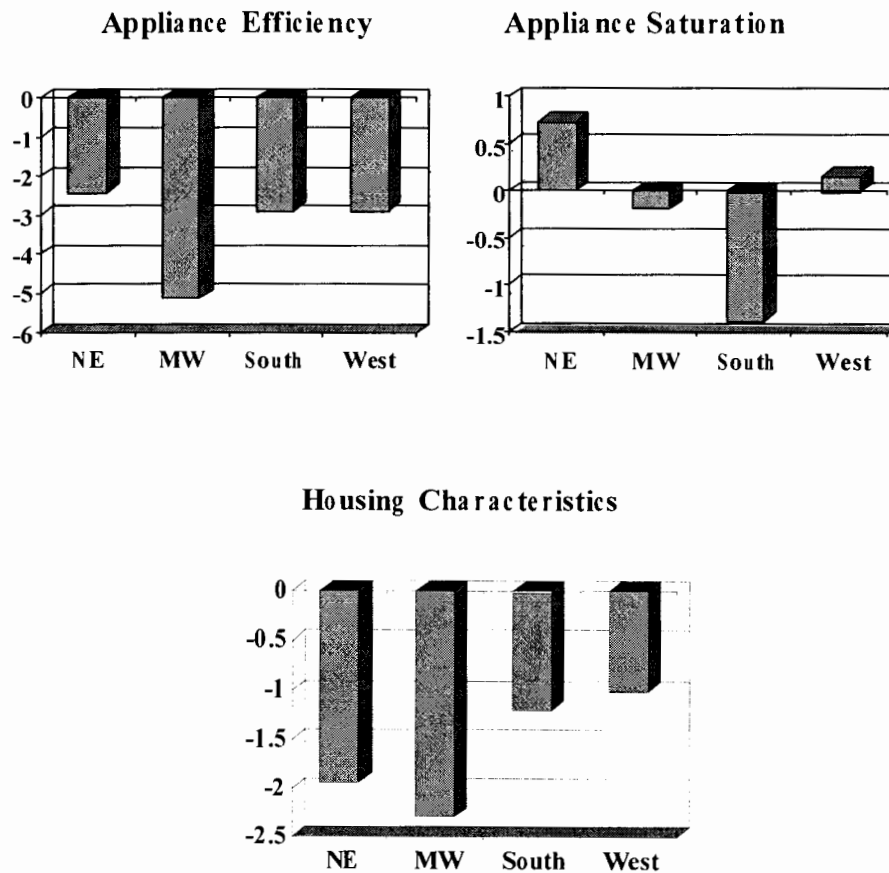
Similar to the findings of the previous analysis, the primary cause of the declining use trend was increasing efficiency of gas appliances, predominately space heaters. Other factors include a reduction in the number of gas appliances in homes served with gas and tighter, more energy efficient homes. Chart 2 shows the estimated proportional impact of the various factors contributing to this decline on a national basis.

Chart 2
Factors Contributing to Declining U.S. Natural Gas Use per Residential Customer 1997-2001



- **Regional variation was observed.** There was a decline in the use per customer in all regions of the country: The Northeast lost 1.74 Mcf/year comparing 1997 to 2001, the South and the West lost 2.17 Mcf/year, and the Midwest 4.31 Mcf/year (Table 1). Graphical representation of some of the factors contributing to these trends can be seen in Chart 3.
- **Space heating efficiency gains** contributed almost half of the residential load loss. In 1997, the average furnace efficiency was estimated to be around 74 percent AFUE, since some furnaces sold before federal regulations set the minimum gas space heating efficiency at 78 percent were still operating. During the study period, some of these less efficient furnaces have been replaced, and by 2001 the current weighted average gas space heating appliance efficiency for all units in place is estimated at roughly 77 percent.
- **Water heating efficiency gains** contributed about 13 percent of the average residential load loss. Federal water heater standards took effect in 1990, setting the minimum gas water heater energy factor (EF) at 0.54, compared to the then-typical 0.5 EF. In addition, consumers are purchasing units with EF ratings higher than 0.54. The 1997 weighted average gas water heating EF is estimated to be slightly less than 0.53, compared to 0.55 in 2001.

Chart 3
Regional Impact of Major Factors
(Change in Mcf/year per residential customer, 1997 - 2001)



Note: Contributing factors are calculated independently and may not total to actual change

- **Space heating market share loss** accounted for about two percent of the overall decrease in gas use per residential customer. The proportion of homes with gas service increased since 1997, but the percentage of those gas homes with gas space heat declined slightly. Thus the relative heating base of gas utilities declined.
 - The market share loss in the Midwest and South was two to nine times as great as the national average. In the Northeast and West, however, there was an increase in space heating gas market share (see Chart 2).
- **Baseload appliance market share loss** accounted for about four percent of the residential load loss experienced from 1997-2001. Overall, the number of gas appliances per customer has declined. The market share loss for water heaters, cooking appliances, clothes dryers was relatively small, while gas light market share losses were somewhat higher.
- **Improved home energy efficiency** was responsible for about 29 percent of the decline. Newer homes with improved thermal envelope characteristics, as well as older homes adding insulation and storm windows/doors, reduced the typical amount of gas needed for space heating.
- **Demographic changes** contributed about six percent of the decline in typical residential gas use. Population shifts of gas customers to warmer climates since 1997 accounted for this decline when viewed from a national perspective. Previously quantified factors such as average number of people per residence and number of households setting back their thermostats at night did not change over the study period.

III. Purpose and Data Limitations

This report attempts to provide a broad-based identification and quantification of factors that impacted the average annual natural gas use per residential customer from 1997 to 2001. Most natural gas distribution utilities experienced a slower growth rate in residential demand compared to the growth rate in the number of residential customers during that time period. This trend makes it more difficult for gas companies to achieve expected revenues and to connect new customers economically. This analysis is intended to help companies understand the driving forces behind the declining use trend by updating the previous study.

The results herein estimate the overall impacts of several contributing factors based on national and regional data. Analysis of utility-specific factors could result in conclusions different from those in this report. Individual companies should use this report as a guide in calculating their specific impacts, and they should include factors and influences pertinent to their systems that may not be considered and/or quantified here.

These contributing factors were examined separately. Some of them may have synergistic properties that compound or offset impacts when considered together. The quantification of these factors is not an attempt to determine absolute values for each influence, but rather to indicate the proportional impact that they have on residential use per customer.

Much of the data used in this analysis come from government and AGA surveys. While this information is the best available for national and regional analysis, survey sampling, structure, and/or extrapolation techniques can be flawed, particularly when ascribing results to smaller populations such as states and jurisdictions.

IV. Overview

A previous AGA analysis calculated that normalized use per residential customer declined 16 percent from 1980 to 1997. Since that time, several gas distribution companies have noted a continuation of this trend, with a number of utilities experiencing higher than expected levels of conservation. This analysis updates the previous report, examining the 1997-2001 time frame.

This analysis shows that residential customers are continuing their efforts to reduce natural gas consumption. On a national average basis, natural gas use per residential customer dropped 6.4 percent from 1997 to 2001, from 89.2 Mcf/year to 83.5 Mcf/year. On a regional basis, these impacts varied. For the Northeast, the average gas use per customer decreased about three percent. Residential gas use per customer dropped eight percent for the Midwest, six percent for the South, and four percent for the West.

Table 1
Trends in Residential Natural Gas Use
(Weather Normalized Mcf/Customer/Year)

	1997	2001	Change, 1997-2001
United States	89.2	83.5	-6.4
Northeast	97.1	94.3	-2.9
Midwest	116.4	107.0	-8.1
South	70.2	66.8	-6.2
West	68.3	65.0	-4.2

Residential gas use can be classified as space heating and non-heating. On average, space heating demand accounts for three-quarters of typical gas consumption by residential customers. This demand is very weather sensitive, with use per customer higher in the colder climates than in the warmer regions.

Residential non-heating use of gas is also known as baseload use. This use is typically not very weather sensitive. The primary residential baseload use is for water heating, which accounts for about 86 percent of non-heating demand, based on national

averages. The other two primary residential gas appliances are cooking equipment and clothes dryers. Natural gas logs/fire places are increasing their market share, and can be used for heating or decorative purposes. Appliances that could also be considered baseload, but have a much lower market penetration, are gas lights, pool heaters, and grills.

V. Contributing Factors

Appliance Efficiency

In response to the energy disruptions of the 1970s, Congress passed the Energy Policy and Conservation Act (EPCA) of 1975. EPCA established an energy conservation program for major household appliances including furnaces, water heaters, refrigerators and freezers, central air conditioners and central air conditioning heat pumps, room air conditioners, dishwashers, clothes washers, clothes dryers, direct heating equipment, pool heaters, kitchen ranges and ovens, fluorescent lamp ballasts, and television sets. The Energy Policy and Conservation Act (EPACT) of 1978 expanded the coverage of EPCA to include commercial building heating and air conditioning equipment, water heaters, certain incandescent and fluorescent lamps, distribution transformers, and electric motors. In 1987, the National Appliance Energy Conservation Act (NAECA), which also incorporates EPCA and EPACT, authorizes the U. S. Department of Energy (DOE) to set energy efficiency standards for major home appliances according to a statutory time schedule stretching into the next century.

DOE's Office of Codes and Standards sets the minimum efficiency ratings of many residential appliances. DOE has set standards for such natural gas appliances as space heaters, water heaters, ovens, and ranges.

Furnaces

During the 1970's natural gas furnaces averaged about 65 percent annual fuel utilization efficiency (AFUE). As interest in more energy efficient appliances increased, the average AFUE for new furnaces increased. DOE, through authority granted by NAECA, set 78 percent AFUE as a minimum for gas furnaces manufactured after January 1, 1992. Furnaces with AFUE ratings up to the mid-90's are available to consumers, and the average AFUE of new residential furnace shipments is currently in the mid-eighties. As the higher efficiency furnaces have worked their way into the residential market in new homes and replacement units, the average AFUE for all residential natural gas furnaces has increased from 65 percent in 1980 to 74 percent in 1997, and to 77 percent by 2001.

Table 2
Residential Natural Gas Furnace Average AFUE
(Percent)

	1980	1997	2001
New Furnace Shipments	66%	85%	86%
All Furnaces In Place	65%	74%	77%

Source for shipment information: Gas Appliance Manufacturers Association

Improvement in overall furnace efficiency caused gas space heating use per customer to fall four percent. However, the impact in terms of sales volume varied by region due to the weather differences. Overall, use per residential customer dropped

about 2.7 thousand cubic feet (Mcf) per year from 1997 to 2001, with regional impacts ranging from 1.7 Mcf in the Northeast to 4.3 Mcf in the Midwest, due to the improved furnace efficiency.

Table 3
Impact of Gas Space Heating Efficiency Gains on Use per Customer
 (Weather-normalized Mcf/year)

	Weighted Average Use per Customer	Reduction in Weighted Average Use per Customer
	1997	2001
United States	61.2	2.7
Northeast	69.8	1.7
Midwest	87.2	4.3
South	44.5	2.2
West	39.1	2.2

Weighted average use per customer = typical use per appliance times the percent of customers with that appliance
Note: Assumes national average furnace efficiency for all regions.

Water Heaters

DOE set the minimum efficiency of natural gas water heater at 0.54 energy factor (EF) for units manufactured after 1989. Starting in 2004, the minimum efficiency will rise to 0.59 EF. Previously, water heaters averaged about 0.5 EF. Industry analysts estimated that the availability of even higher efficiency units raised the average EF of new units sold to 0.57 by the 2001. Based on shipment data and typical retirement rates, the average EF of water heaters went from 0.53 in 1997 to 0.55 in 2001.

Table 4
Residential Natural Gas Water Heater Average EF
 (Percent)

	1980	1997	2001
New Water Heater Shipments	50%	53%	57%
All Water Heaters In Place	50%	53%	55%

Since the average water heater EF improved slightly less than four percent from 1997, the typical consumption by residential customers that have water heaters declined in the same proportion. The average decline was 0.8 Mcf per customer, with regions not varying much from that average.

Table 5
Impact of Gas Water Heating Efficiency Gains on Use per Customer
(Mcf/year)

	Weighted Average Use per Customer	Reduction in Weighted Average Use per Customer
	1997	2001
United States	23.9	0.8
Northeast	22.3	0.7
Midwest	25.6	0.8
South	23.5	0.8
West	23.3	0.8

Weighted average use per customer = typical use per appliance times the percent of customers with that appliance

Appliance Saturation

The most common natural gas appliances found in homes are space heaters, water heaters, cooking equipment, clothes dryers, and, to a lesser extent, outdoor lights. All of these applications face competition from other energy forms, particularly electricity. Since 1997 the average number of gas appliances found in homes has dropped. This trend, discussed below, contributes to the decline in gas use per residential customer.

Space Heaters

The percentage of gas customers that use natural gas as their main space heating fuel declined by 0.2 percentage points over the four year period. Regionally, the Northeast and West regions saw an increase in this market penetration among its customers. The Midwest loss mirrored the national average. The South region exhibited significant declines in the proportion of their customers that use gas for their main space heating fuel. A primary contributing factor to this decline is the increasing popularity of the heat pump during this time. Not only did heat pumps make significant inroads into new construction (particularly in multi-family housing), electric utilities encouraged existing gas customers to add on heat pumps and use their gas furnaces as back-up systems.

Table 6
Natural Gas Space Heating Appliance Market Penetration
(Percent of all gas customers)

	1997	2001
United States	84.4%	84.2%
Northeast	71.7%	72.8%
Midwest	93.8%	93.5%
South	83.9%	81.5%
West	84.1%	85.0%

Source: American Housing Survey, Bureau of the Census, various years

Since the overall change for gas space heating market penetration was not substantial, it caused a decrease in heating use of less than one percent for the average U.S. gas customer. This was also true for the typical Midwest gas customer. The Northeast gas utilities experienced a gain of more than 1.1 percent in heating use per

customer due to increased market penetration for space heating. The West region experienced increasing space heating demand per customer of one percent due to the increase in market penetration. The South region's use per customer decreased 2.5 percent due to reduced space heating penetration.

Table 7
Impact of Gas Space Heating Market Penetration on Use per Customer
(Mcf/year)

	Weighted Average Space Heating Use per Customer	Change in Weighted Average Space Heating Use per Customer
	1997	2001
United States	61.2	-0.1
Northeast	69.8	+0.8
Midwest	87.2	-0.2
South	44.5	-1.1
West	39.1	+0.4

Weighted average use per customer = typical use per appliance times the percent of customers with that appliance

Water Heaters

Water heaters contribute significantly to a utility's load profile. Demand by these appliances is relatively non-weather sensitive, allowing for optimal utilization of utility investment. Also, these appliances can use as much gas as a furnace in some regions. Therefore, any loss in market penetration or improvements in efficiency will impact noticeably on average use per customer.

In most areas, market penetration of gas water heaters changed marginally between 1997 and 2001. Overall, penetration declined slightly. Regionally, the Northeast's, South's and West's market penetration decreased, with the Midwest increasing somewhat.

Table 8
Natural Gas Water Heater Market Penetration
(Percent of all gas customers)

	1997	2001
United States	84.2%	84.0%
Northeast	77.9%	77.8%
Midwest	86.2%	86.6%
South	79.0%	78.3%
West	91.9%	91.2%

Source: American Housing Survey, Bureau of the Census, various years

When the proportion of gas customers with gas water heaters declines, the weighted average gas use per customer declines. For example, the national average penetration of water heaters fell 0.2 percentage points from 1997 to 2001, resulting in a decline in overall gas use per customer of 0.05 Mcf/year. The South and West regions' losses averaged about 0.16 Mcf/year, while the Northeast region loss was minor, 0.02

Mcf/year. Conversely, a slight increase in penetration in the Midwest led to a 0.1 Mcf/year increase.

Table 9
Impact of Gas Water Heater Market Penetration on Use per Customer
(Mcf/year)

	Weighted Average Water Heating Use per Customer	Change in Weighted Average Water Heating Use per Customer
	1997	2001
United States	22.7	-0.05
Northeast	19.9	-0.02
Midwest	22.2	+0.10
South	20.4	-0.17
West	23.7	-0.16

Weighted average use per customer = typical use per appliance times the percent of customers with that appliance

Cooking

The percentage of gas customers that cook with gas declined in all regions but the West, due to electric products dominating the new home market, even those homes with gas service, as well as replacing old gas units. Nationally, cooking market penetration for gas customers fell 2.6 percent, with the Northeast falling 1.3 percent, the Midwest 5.0 percent, and the South 4.0 percent. The West increased slightly.

Table 10
Natural Gas Cooking Appliance Market Penetration
(Percent of all gas customers)

	1997	2001
United States	58.6%	57.1%
Northeast	77.2%	76.2%
Midwest	52.4%	49.8%
South	53.0%	50.9%
West	56.6%	56.8%

Source: American Housing Survey, Bureau of the Census, various years

Despite the significance of the decline for gas cooking penetration, the resulting impact is relatively small. This is due to the smaller proportion of gas customers with this appliance combined with the modest annual energy consumption from these units. For all regions, the change amounted to less than 0.11 Mcf annually.

Table 11
Impact of Gas Cooking Market Penetration on Use per Customer
(Mcf/year)

	Weighted Average Cooking Use per Customer	Change in Weighted Average Cooking Use per Customer
	1997	2001
United States	2.5	-0.06
Northeast	3.2	-0.04
Midwest	2.2	-0.11
South	2.2	-0.09
West	2.4	+0.01

Weighted average use per customer = typical use per appliance times the percent of customers with that appliance

Clothes Dryers

Penetration of gas dryers increased slightly in all regions but the South (four percent decline) from 1997 to 2001, ranging from one percent in the Northeast to six percent in the West.

Table 12
Natural Gas Clothes Dryer Market Penetration
(Percent of all gas customers)

	1997	2001
United States	27.0%	27.5%
Northeast	29.4%	29.7%
Midwest	32.6%	33.4%
South	16.0%	15.4%
West	29.0%	30.7%

Source: American Housing Survey, Bureau of the Census, various years

These changes in penetration for gas clothes dryers resulted in marginal changes in typical use per customer, less than one-tenth Mcf in the regions.

Table 13
Impact of Gas Drying Market Penetration on Use per Customer
(Mcf/year)

	Weighted Average Drying Use per Customer	Change in Weighted Average Drying Use per Customer
	1997	2001
United States	1.1	+0.02
Northeast	1.3	+0.01
Midwest	1.3	+0.03
South	0.7	-0.03
West	1.3	+0.07

Weighted average use per customer = typical use per appliance times the percent of customers with that appliance

Outdoor Gas Lights

Natural gas lights were somewhat popular with customers through mid-1970s. During the turmoil in the energy markets in the late-70s, President Carter encouraged people to turn their gas lights off or convert them to electricity. Since that time, their market share for gas customers fell significantly. The decline continued from 1997 (1.5 percent market penetration among gas customers) through 2001 (0.8 percent). Assuming typical gas light usage of 19 Mcf per year, the decline in market share caused the weighted average gas use per residential customer to decline about one-tenth Mcf per year on a national average. No data were available for regional comparisons.

Housing Characteristics

Thermal Efficiency

Homes across the country have become more energy efficient due, in part, to the improved thermal efficiency of the building envelope. New homes, which must meet local regulations implemented over the last two decades regarding thermal efficiency, account for most of this improvement. In addition, many homeowners have retrofitted older residences in order to cut their energy bills.

According to estimates from the U. S. Department of Energy's Energy Information Administration,² the average residential building was three percent more efficient in 2001 compared to the 1997 average. This improvement in thermal efficiency reduced the heating demand from the residential sector. Overall, typical consumption decreased by about 1.6 Mcf nationally. Regionally, the decrease in weighted average gas use per customer ranged from about one Mcf in the West to more than two Mcf in the Northeast.

Table 14
Impact of Improving Home Thermal Efficiency on Gas Demand
(Decrease in Mcf per Residential Customer per Year)

United States	1.63
Northeast	1.94
Midwest	2.30
South	1.20
West	1.02

Other

Geographic Population Shifts

From 1997 to 2001, population growth, and subsequently gas customer growth, was greater in the warmer regions (South and West) than in the colder regions (Northeast and Midwest). About 51 percent of the residential gas customers were in the warmer Southern and Western sections of the country in 1997, compared to 52 percent in 2001. With more of the households in warmer climates, the average heating demand,

² Annual Energy Outlook, Energy Information Administration, various years.

on a national basis, declined. This larger percentage of gas customers in warmer climates resulted in overall use per gas customer falling about 0.33 Mcf on a national basis. This factor does not impact typical regional use per gas customer.

Table 15
Regional Natural Gas Customer Population Trends
(Percent of all gas customers)

	1997	2001
United States	100.0%	100.0%
Northeast	19.2%	18.9%
Midwest	29.7%	28.9%
South	26.9%	28.0%
West	24.2%	24.3%

Source: *RECS: Housing Characteristics*, Energy Information Administration, U.S. Dept. of Energy, various years.

Other Factors

Several factors did not change substantially between 1997 and 2001, and therefore should not have measurably impacted use per customer. The table below shows national factors for such items as thermostat settings for each of the years.

Table 16
Natural Gas Customer Characteristics

	1997	2001
Age of Home	33.1 years	34.6 years
Age of Furnace	13.8 years	13.6 years
Avg. Winter Day Temp	70.2 degrees	70.2 degrees
Avg. Winter Night Temp	67.8 degrees	68.0 degrees
Setback Temp Day	45% do	49% do
Setback Temp Night	47% do	47% do
Avg. Persons per Home	2.64	2.61

Source: *RECS: Housing Characteristics*, Energy Information Administration, U.S. Dept. of Energy, various years.

Other Factors Not Quantified

Other factors could have an impact on residential natural gas use, but were not quantified here, primarily due to lack of data. For the most part, these should have impacts less than most of those factors listed above. Some of these factors include:

Water Conservation – Low flow showerheads and increasingly efficient dishwashers and washing machines have decreased the amount of hot water needed per residence.

Economic Influences – Changes in the price of natural gas and in the general economic condition of the general population influence consumption.

Environmental Regulations – Restrictions on certain combustion practices, such as wood fireplaces, may impact consumer purchases of gas products.

Gas Hearth Products – Gas fireplace/logs have become more popular over the past few years, but it is not clear whether these units actually add to load. Some units could displace gas furnace requirements.

Unoccupied/Seasonal Homes – The rise in second home ownership combined with increasing vacancy rates for rental homes could reduce overall use per customer.

VI. National & Regional Summaries

Table 17 summarizes the factors contributing to the decline in use per residential customer. The sum of the estimated factors closely approximates the observed decline for the United States. Regional comparisons do not provide as close a fit. Keep in mind that this report provides a broad-based assessment to the factors contributing to the decline in order to provide an understanding of the relative impact from each of these factors. This report does not attempt to provide precise measures of these factors due to limitations in the data.

Table 17
Summary of Factor Quantification and Comparison to Actual Decline
(Change in use per residential customer, 1997-2001 Mcf/year)

	U.S	NE	MW	South	West
Space Heating Efficiency	-2.68	-1.74	-4.31	-2.17	-2.17
Baseload Appliance Efficiency	-0.77	-0.71	-0.82	-0.75	-0.75
Space Heating Market Penetration	-0.12	+0.79	-0.22	-1.09	+0.38
Baseload Appliance Market Penetration	-0.22	-0.05	+0.03	-0.29	-0.08
Thermal Efficiency Gains	-1.63	-1.94	-2.30	-1.20	-1.02
Population Trends	-0.33	N/A	N/A	N/A	N/A
Total	-5.75	-3.65	-7.62	-5.50	-3.64
Actual Change	-5.71	-2.83	-9.39	-4.40	-2.86
Difference**	-0.04	-0.82	1.77	-1.10	-0.78

**Can be due to a variety of factors, including data error, omission of other factors, and imprecise methodology

IX. Methodology

Normalized Use Per Customer

- Calculate actual use per residential customer from EIA data³
- Determine heating portion of use based on AGA survey data⁴
- Determine weather normalization factor by dividing the 30-year (1961-1990) normal heating degree days into the actual degree days, based on NOAA data⁵
- Divide heating portion by weather normalization factor, and add back in non-heating load

³ Natural Gas Annual, various years, Energy Information Administration, U.S. Department of Energy, Washington, DC.

⁴ Residential Natural Gas Market Survey, various years, American Gas Association, Washington, DC.

⁵ State, Regional, and National Monthly and Seasonal Heating Degree Days, various years, National Oceanic and Atmospheric Administration, U.S. Department of Commerce, Washington, DC.

Average Space Heating AFUE

- Assume 65% AFUE as standard in 1980 and all retirements are those units
- Estimate new construction units by subtracting previous year's gas space heating customers from current year's, based on trend analysis of EIA RECS data⁶
- Calculate replacement units by subtracting new construction units from total shipments based on GAMA data⁷
- Eliminate the retired units from the inventory, and add in the new units, calculating the revised weighted average furnace AFUE for all existing units based on average AFUE of shipments as provided by GAMA

Space Heating Efficiency Impact

- Calculate average use per customer by multiplying the normalized heating load by the percent of gas customers with gas space heating (based on EIA RECS data)
- Calculate change in average furnace AFUE by dividing 1997 AFUE value into the selected year's AFUE value
- Calculate the efficiency-adjusted demand by dividing the 1997 average use per customer by the change in average furnace AFUE for the selected year
- Subtract the efficiency-adjusted demand from the 1997 average use per customer to determine impact

Average Water Heating EF

- Assume 0.50 EF as standard in 1980 and all retirements are those units
- Estimate new construction units by subtracting previous year's gas water heating customers from current year's, based on trend analysis of EIA RECS data
- Calculate replacement units by subtracting new construction units from total shipments based on GAMA data
- Eliminate the retired units from the inventory, and add in the new units, calculating the revised weighted average furnace EF for all existing units based on average EF of shipments estimated at 0.54 EF to 0.56 EF

Water Heating Efficiency Impact

- Calculate average use per customer by multiplying the water heating load (based on AGA survey data) by the percent of gas customers with gas water heating (based on EIA RECS data)
- Calculate change in average EF by dividing 1997 EF value into the selected year's EF value
- Calculate the efficiency-adjusted demand by dividing the 1997 average use per customer by the change in average water heater EF for the selected year
- Subtract the efficiency-adjusted demand from the 1997 average use per customer to determine impact

⁶ RECS: Housing Characteristics, various years, Energy Information Administration, U. S. Department of Energy, Washington, DC.

⁷ GAMA News, various years, Gas Appliance Manufacturers Association, Arlington, VA.

Appliance Market Penetration Impact

- Calculate appliance penetration by dividing the number of residences with gas service by the number of customers with that appliance, based on EIA RECS data
- Subtract the impact year penetration from the 1997 penetration to determine the change in market penetration
- Calculate the weighted average gas use per customer for that appliance by multiplying the penetration value times the typical gas use for that appliance
- Multiply the change in market penetration by the 1997 weighted average use of that appliance to determine the reduction in weighted average use per customer for that appliance

Thermal Efficiency Impact

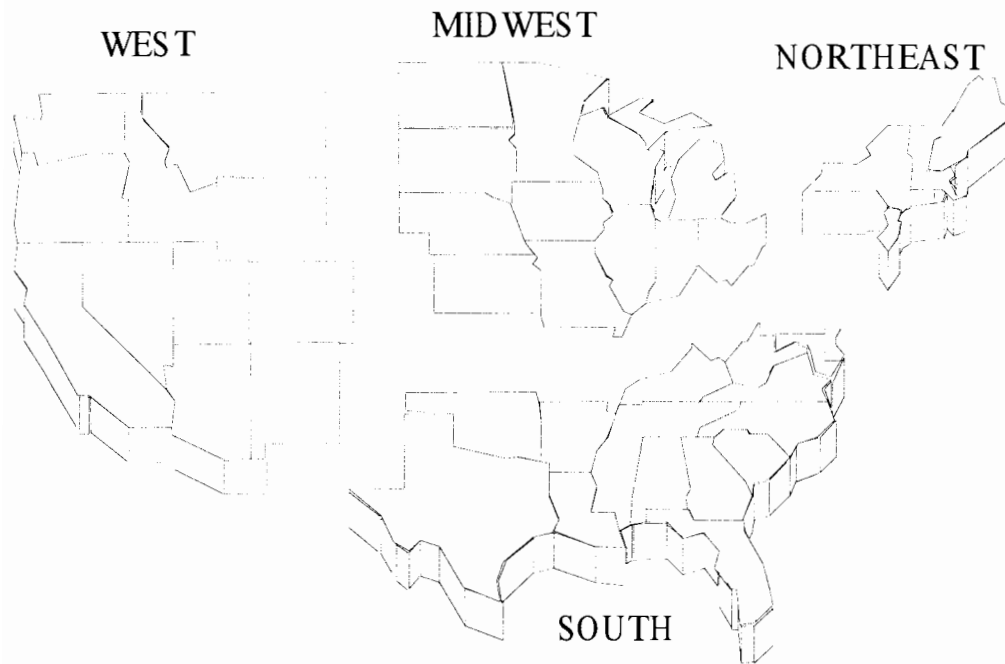
- Obtain an estimate of average percent increase thermal home efficiency enhancements from current and past EIA forecasts⁸
- Multiply the thermal efficiency percent increase by the percent difference in heating load and by the percent of gas homes with gas space heating to determine the thermal efficiency impacts

Population Shift Impact

- Determine the percent of gas customers by region for 1997 and 2001 from EIA RECS data
- Determine the normalized heating demand for those regions in 1997 based on AGA survey data
- Apply those same regional demand figures to the 2001 regional population distribution, calculate the weighted average national numbers for both, and compare the two numbers

⁸ *Annual Energy Outlook*, various years, Energy Information Administration, Washington, DC.

Appendix
US Census Regions



STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

NORTH SHORE GAS COMPANY	)	
	)	
Proposed General Increase	)	No. 07-0241
In Rates for Natural Gas Service	)	
	)	
	)	
THE PEOPLES GAS LIGHT AND	)	
COKE COMPANY	)	
	)	
Proposed General Increase	)	No. 07-0242
In Rates for Natural Gas Service	)	

DIRECT TESTIMONY OF MICHAEL L. BROSCHE

ON BEHALF OF

THE PEOPLE OF THE STATE OF ILLINOIS

THE CITY OF CHICAGO AND

THE CITIZENS UTILITY BOARD

JULY 3, 2007

GCI EXHIBIT 1.0

DIRECT TESTIMONY OF MICHAEL L. BROSCHE

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EXHIBIT LIST

GCI Exhibit No. MLB-1.1 Summary of Qualifications

GCI Exhibit No. MLB-1.2 Prior Testimony Listing

GCI Exhibit No. MLB-1.3 Response to AG Data Request No. 3.06

GCI Exhibit No. MLB-1.4 Response to AG Data Request No. 5.23

GCI Exhibit No. MLB-1.5 Response to AG Data Request No. 3.14

GCI Exhibit No. MLB-1.6 Response to AG Data Request No. 4.05

GCI Exhibit No. MLB-1.7 Response to AG Data Request No. 4.15

GCI Exhibit No. MLB-1.8 Response to Staff Data Request No. DLH-1.03

GCI Exhibit No. MLB-1.9 Response to AG Data Request No. 8.02

1

2

I. INTRODUCTION / SUMMARY

3

4 **Q. Please state your name, occupation and address.**

5 A. My name is Michael L. Brosch. My business address is 740 North Blue Parkway,
6 Suite 204, Lee's Summit, Missouri 64086.

7

8 **Q. By whom are you employed?**

9 A. I am a principal in the firm Utilitech, Inc., a consulting firm engaged primarily in
10 utility rate and regulation work. The firm's business and my responsibilities are
11 related to special services work for utility regulatory clients. These services include
12 rate case reviews, cost of service analyses, jurisdictional and class cost allocations,
13 financial studies, rate design analyses and focused investigations related to utility
14 operations and ratemaking issues.

15 **Q. On whose behalf are you appearing in this proceeding?**

16 A. I am appearing on behalf of the People of the State of Illinois, represented by the
17 Attorney General, the Citizens Utility Board and the City of Chicago (collectively
18 "Governmental and Consumer Intervenors" or "GCI") in order to review and
19 respond to certain non-traditional rate tracking proposals raised by Peoples Gas
20 Light & Coke Company ("PGL") as part of its filing for an increase in its gas rates
21 and revenues. I am also appearing on behalf of the Attorney General and CUB in
22 order to review and respond to similar non-traditional rate tracking proposals raised
23 by North Shore Gas Company ("North Shore" or "NSG") in its rate filing.

1 **Q. Will you summarize your educational background and professional experience**
2 **in the field of utility regulation?**

3 A. GCI Exhibit No. MLB 1.1 is a summary of my education and professional
4 qualifications. I have testified before utility regulatory agencies in Arizona,
5 Arkansas, California, Florida, Hawaii, Illinois, Indiana, Iowa, Kansas, Michigan,
6 Missouri, New Mexico, Ohio, Oklahoma, Utah, Washington, and Wisconsin in
7 regulatory proceedings involving electric, gas, telephone, water, sewer, transit, and
8 steam utilities. In Illinois, I have testified in two major proceedings before the
9 Commission. The first involved a PGL rate case in Docket No. 90-0007. The
10 second matter concerned Illinois Bell Telephone Company in Docket Nos. 92-0448
11 and 92-0239.

12 **Q. Have you previously participated in energy utility regulatory proceedings in**
13 **other states?**

14 A. Yes. I have participated in many electric and gas regulatory proceedings, as listed
15 and described in GCI Exhibit No. MLB 1.2. While much of my experience
16 involves traditional rate increase or rate reduction cases, I have also addressed rate
17 adjustment tracking tariffs as well as deferral accounting proposals on many prior
18 occasions.

19 **Q. What is the purpose of your testimony in this docket?**

20 A. My testimony addresses certain regulatory policy concerns raised by the four newly
21 proposed rate adjustment tracking mechanisms or riders being advocated by PGL
22 and three similar proposals of North Shore. The first proposed new tracking
23 mechanism proposed by both PGL and NSG would partially “decouple” gas margin

1 recovery to account for variations in usage per customer between rate cases through
2 a so-called “Volume Balancing Adjustment” (or “Rider VBA”) tariff.¹ A second
3 new tracking tariff is proposed by Peoples, but not by North Shore, and would
4 increase prices to customers when future new capital investment in certain plant
5 accounts exceeds historical average levels. This proposal is captioned the
6 “Infrastructure Cost Recovery” or “Rider ICR” tariff.² The Companies’ third new
7 rate tracker proposal would adjust rates for changes in uncollectibles expense
8 associated with the gas commodity cost portion of customers’ bills, which the
9 Companies have labeled an “Uncollectible Balancing Adjustment” or “Rider
10 UBA”.³ A fourth new rate tracking mechanism proposed by the Companies would
11 adjust gas utility service rates between future rate cases on a single-issue basis using
12 what the Companies have labeled their “Enhanced Efficiency Program” or “Rider
13 EEP”, which is intended to fund the costs of the Companies’ conservation program
14 funding.⁴

¹ Direct Testimony of Lawrence T. Borgard, PGL Ex. LTB-1.0, pp. 23-26, NSG Ex. LTB-1.0, pp. 21-24; Direct Testimony of Russell A. Feingold, PGL Ex. RAF-1.0, pp. 13-36, NSG Ex. RAF-1.0, pp.12-33; Direct Testimony of Valerie H. Grace, PGL Ex. VG-1.0, pp.46-48 NSG Ex. VG-1.0, pp.41-44; PGL Ex. VG-1.1, pp.57-60; NSG Ex. VG-1.1,pp.55-58.

² Direct Testimony of Lawrence T. Borgard, PGL Ex. LTB-1.0, pp. 28-29; Direct Testimony of Russell A. Feingold, PGL Ex. RAF-1.0, pp. 44-46; Direct Testimony of James F. Schott, PGL Ex. JFS-1.0, pp. 2-13; Direct Testimony of Valerie H. Grace, PGL Ex. VG-1.0, pp.48-50, PGL Ex. VG-1.1, pp. 142-144.

³ Direct Testimony of Lawrence T. Borgard, PGL Ex. LTB-1.0, pp. 26-28, NSG Ex. LTB-1.0, pp. 24-26; Direct Testimony of Russell A. Feingold, PGL Ex. RAF-1.0, pp. 36-42, NSG Ex. RAF-1.0, pp. 34-39; Direct Testimony of Valerie H. Grace, PGL Ex. VG-1.0, pp.44-46, NSG Ex. VG-1.0, pp. 39-41; PGL Ex. VG-1.1, pp. 54-56; NSG Ex. VG-1.1, pp.52-54.

⁴ Direct Testimony of Lawrence T. Borgard, PGL Ex. LTB-1.0, p.22, NSG Ex. LTB-1.0, p.20; Direct Testimony of Russell A. Feingold, PGL Ex. RAF-1.0, pp. 42-44, NSG Ex. RAF-1.0, pp.39-41; Direct Testimony of Valerie H. Grace, PGL Ex. VG-1.0, pp.40-43 NSG Ex. VG-1.0, pp. 35-39; PGL Ex. VG-1.1, pp. 51-53; NSG Ex. VG-1.1, pp. 49-51.

1 **Q. Please summarize the recommendations that are set forth in your testimony.**

2 A. In general, I recommend that the Commission reject piecemeal rate adjustment
3 tariff riders for isolated elements of utility revenue requirements in the absence of
4 compelling evidence that such piecemeal rate adjustments are warranted. My
5 testimony explains how traditional test-year regulation achieves an important
6 balanced measurement of revenue requirement that accounts for all changes in
7 revenues and costs. I then describe how tracking tariff riders and deferral
8 accounting methods can be used as exceptions to the normal test-year approach,
9 when warranted by extraordinary circumstances. I explain several general criteria
10 that should be satisfied before piecemeal cost tracking rider tariffs should be
11 accepted by regulators. My testimony explains why, when these criteria are applied
12 to the specific VBA, ICR, UBA and EEP tariff mechanisms proposed by the
13 Companies, the Commission should reject these proposals. My testimony also
14 rebutts specific claims of the Companies' witnesses in support of each of the newly
15 proposed tariff riders.

16

17 **II. TEST PERIOD RATEMAKING CONCEPTS**

18 **Q. What is a test period and how is it used in utility regulation?**

19 A. Energy utilities have traditionally been regulated based upon their cost to provide
20 service, including an opportunity to earn a reasonable return on invested capital.
21 The process used to evaluate and measure the cost of service and resulting revenue
22 requirement is the rate case, in which a balanced review of jurisdictional expenses,
23 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.” In Illinois, the test period can be a recent actual 12-month historical period of time within which revenues at present rate levels are compared to operating expenses and the required return on rate base, to determine whether an overall increase or reduction in revenue levels is needed. Alternatively, a projected or “Future” test year can also be employed in Illinois, if elected by the utility.⁵

Q. Does a test year impose limits upon the time period for measurement of revenues, expenses and rate base investments?

A. Yes. It is essential that there be a synchronized review of both revenue levels and cost levels to occur within a carefully structured test period, because both revenues and costs tend to change over time as customers are added and lost, inflation and productivity changes impact costs, capital market conditions change and sales volumes fluctuate. The dynamic nature of utility costs and revenues does not necessarily imply the need for frequent rate cases. As long as revenues and costs remain in approximate balance, causing the utility’s earnings to stay within acceptable proximity to authorized return levels, an electric or gas utility may be able go many years between rate cases. This has been the case with PGL and North Shore, as neither company has filed a rate case since 1995.⁶

Q. Does utility price regulation based upon cost of service cause the public utility to be indifferent about its cost levels?

⁵ 83 Ill. Adm. Code Section 287.20 provides that a utility may, at its option, propose either an historical or a future test year. Section 287.40 permits pro-forma adjustments for known and measurable changes occurring or reasonably certain to occur within 12 months after the filing date of the tariffs. If a future test year is used, Section 287.30 permits updating of the filing upon approval of the assigned Administrative Law Judge.

⁶ PGL Ex. LTB-1.0 at 8; NS Ex. LTB-1.0 at 8.

1 A. No. An important element of traditional test period regulation is the incentive
2 created for management to control and reduce costs, so as to maximize the
3 opportunity to actually earn at or above the authorized return level between rate
4 case test periods. Traditional test year regulation is not continuous regulation,
5 because prices established in a rate case are normally fixed for a period of years,
6 causing any changes in actual costs or sales levels to be subject to “regulatory lag”
7 before such changes can be translated into revised prices after a “next” rate case.
8 Thus, regulatory lag serves to replace some of the efficiency incentive that is lost
9 when prices are based upon costs to serve.

10 Another beneficial characteristic of traditional test year regulation is the
11 intensive focus upon utility operations and costs within a formal proceeding in
12 which Commission Staff and other interested parties can carefully examine or audit
13 the components making up the revenue requirement. The potential for regulatory
14 disallowance of excessive or imprudently incurred costs in such formal proceedings
15 represents another form of efficiency incentive to management. In contrast,
16 piecemeal rate tracking tariff adjustments often receive reduced scrutiny or input
17 from regulators and consumer representatives, even though significant customer
18 impacts can result from such tariffs. These mechanisms place an added burden on
19 Commission Staff and intervenors, and ultimately regulatory bodies are likely to
20 give less scrutiny to these piecemeal cost and price changes.

21 **Q. Under traditional test period rate case regulation, what normally happens**
22 **when a specific utility expense changes between test periods?**

1 A. Increases in specific individual expenses between test periods, if nothing else
2 changes, would directly impact the utility's pre-tax earnings and the achieved rate of
3 return. Regulatory "lag" causes such changes to be borne or enjoyed by
4 shareholders between rate cases. However, all of the utility's costs and revenues
5 tend to change over time. Customer and revenue growth or reductions in other costs
6 can serve to offset or mitigate isolated cost changes, such that a utility company
7 may be able to avoid filing a rate case for extended periods of time. Sustained cost
8 increases that are not offset by reductions in other costs or by increases in customer
9 or sales levels may contribute to declines in achieved returns sufficient to justify the
10 filing of a petition to increase rates. However, whenever a rate case does occur, all
11 of the elements of revenue requirement are again measured and adjusted, in a
12 balanced overall review that should account for cost increases in some areas being
13 offset by cost savings in other areas. For example, here, the Companies are
14 accounting for their current customer counts and sales volumes as well as updated
15 operating expenses and the current cost of capital in these Dockets, at the same time
16 changes in rate base and depreciation expenses are considered. Commission Staff
17 and Intervenor witnesses then have an opportunity to review and comment upon the
18 revenue, expense and cost of capital figures presented by the Companies. This
19 balanced review of all elements of revenue requirement is a key characteristic of
20 traditional regulation.

21 **Q. Does the use of a projected or "future" test period approach, as compared to**
22 **the actual or "historical" test period approach, change the balance that is**
23 **achieved among test period ratemaking elements?**

1 A. No. A balanced and matched measurement of the revenue requirement elements is
2 still pursued. Several state regulatory commissions, including Illinois, allow
3 projected (a.k.a. future) test period ratemaking using budgeted information, rather
4 than actual recorded accounting data from a historical year. Use of such projected
5 test period financial data introduces management, staff and intervenor judgment and
6 debate regarding how sales volumes, employment levels, non-labor expenses and
7 rate base investments may change in the future rate-setting period. However, the
8 desired end-result is still a matched comparison of revenues to costs within an
9 internally consistent test period. The choice of test year approach, projected versus
10 historical, does not change the need for a balanced comparison of revenues at
11 present rates to the overall cost of service in order to determine rate changes that are
12 needed. Unfortunately, while presumed to be desirable at reducing regulatory lag,
13 projected test year analyses are inherently more complex in practice because of
14 difficulties associated with accurately predicting future events, documenting
15 assumed future events in the absence of factual data and the challenges involved in
16 defending such predictions upon critical review in a litigation setting.

17 **Q. What are the most common types of exceptions to the standard approaches to**
18 **test period rate case regulation of energy utilities that you have described?**

19 A. Exceptions to the holistic test period review of revenues and costs have been
20 allowed in limited instances by regulators for certain large and volatile cost
21 elements that are predominately beyond the control of utility management and that
22 might produce unacceptable financial outcomes if not allowed special treatment.

1 The most common exception to traditional test period regulation is the
2 widespread utilization of purchased fuel/energy adjustment clauses to periodically
3 adjust rates, so as to track changes in the costs of purchased gas for local gas
4 distribution utilities or to track changes in the costs of generation fuel and/or
5 purchased power incurred by electric utilities. Fuel Adjustment Clause (“FAC”)
6 and Purchased Gas Adjustment (“PGA”) mechanisms are employed by many state
7 regulators because fuel and purchased energy commodity costs are often recognized
8 to be:

- 9 • Large in relation to the total cost to provide electric service;
- 10 • Subject to market forces (rather than management control);
- 11 • Volatile enough to cause unacceptable earnings volatility if not tracked.

12 Another exception to traditional test period regulation that occurs with
13 some regularity is the concept of deferral accounting, which is sometimes referred
14 to as an accounting authority order. For designated transactions or types of costs,
15 the utility may be allowed to deviate from the accounting otherwise required under
16 Generally Accepted Accounting Principles (“GAAP”) or the Federal Energy
17 Regulatory Commission (“FERC”) accounting principles set forth in the Uniform
18 System of Accounts (“USOA”). Examples of accounting deferral orders might
19 include extraordinary storm recovery costs or deferral of costs associated with
20 merger transaction and transition costs, in an effort to mitigate the financial impact
21 of extraordinary events or to better match cost recognition to the periods thought to
22 benefit from a merger of utility entities. Deferral accounting is typically also

1 employed to recognize timing differences that occur when tariff rider recovery is
2 allowed under FAC and PGA mechanisms.

3 **Q. Why is a discussion of traditional test period regulation, versus rate tracking**
4 **and deferral accounting, relevant to these PGL and NSG rate case**
5 **proceedings?**

6 A. As noted above, Peoples and North Shore are requesting Commission approval of
7 several new piecemeal rate tracking tariff riders to change rate levels between rate
8 cases. However, such extraordinary regulatory treatment should be used only in
9 instances where there is compelling evidence that piecemeal ratemaking is in the
10 public interest. It is my belief that parties to regulatory proceedings should not be
11 allowed to tinker with the balance inherent in traditional test period ratemaking
12 processes, by isolating certain revenue or cost elements for rate rider tracking or
13 deferral accounting treatment in the absence of compelling evidence that traditional
14 regulation is not working effectively.

15 **Q. What general problems are created by the use of rate tracking tariff riders and**
16 **accounting deferrals?**

17 A. The fundamental problem associated with use of these regulatory tools is the
18 potentially serious distortion of the “matching” that is desirable in a rate case test
19 year. This is often referred to as the “matching principle” in ratemaking. It
20 recognizes the importance of matching all revenues and costs (expenses, rate base,
21 rate of return) at a consistent period of time within a balanced test year to determine
22 needed changes in utility pricing.

1 As I mentioned in prior testimony, under traditional test year ratemaking, all
2 elements of the revenue requirement calculation are dynamic through time and
3 changes that are favorable tend to offset other changes that are unfavorable. For
4 example, adding customers and the related revenue growth can help “pay for”
5 increases in operating expenses, while growth in the depreciation reserve or the
6 refinancing of high-cost debt can help to offset costs of new construction activity
7 that adds new Plant in Service.⁷ If a party is allowed to select certain items for
8 special treatment with a rate rider or through deferral accounting, one can
9 reasonably expect that the selected items will be “cherry picked” by that advocate
10 so as to influence the regulatory process to the sole advantage of that party.

11 Other specific concerns with the use of rate riders in place of balanced test
12 year analysis include:

- 13 • Reduction of management incentives (by eliminating regulatory lag);
- 14 • Shifting of cost responsibility and risk to customers who are least able
- 15 to influence cost levels or sales levels;
- 16 • Increases in tariff and bill complexity that may be difficult to explain
- 17 to customers or that may complicate customers’ ability to control their
- 18 costs;
- 19 • Administrative complexity and costs associated with audit verification,
- 20 and administration of complex accounting entries, cost allocations
- 21 and/or tariff calculations, often on an accelerated procedural schedule;
- 22 and
- 23 • Potential for inadequate regulatory oversight and auditing of tariff
- 24 application.
- 25
- 26
- 27
- 28
- 29

⁷ New customers increase utility sales volumes, yielding margin revenues (revenues less gas costs) that contribute toward recovery of the fixed costs of the business. Some incremental non-gas 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 With these concerns in mind, I believe that such exceptions to normal test year
2 ratemaking, using rate riders and/or deferral accounting, should only be allowed
3 when extraordinary circumstances exist that preclude the setting of just and
4 reasonable rates through traditional test year procedures.

5 **Q. Is the matching principle an important element of utility regulatory policy in**
6 **Illinois?**

7 A. Yes. I am advised by counsel that Part 287 of the Commission's rules requires a
8 utility to file its rate data in accordance with a proposed test year that has the salutary
9 purpose of preventing the utility from mismatching revenues and expenses.

10 **Q. In prior testimony, you described how the balanced measurement of all**
11 **elements of the revenue requirement within a test period is important. What is**
12 **"regulatory lag" and how does it impact regulated public utilities?**

13 A. Regardless of whether we use actual historical test period data or projected future
14 test period financial estimates to determine public utility revenue requirements, there
15 will always be a "lag" between the timing of available financial data that is
16 incorporated into evidence upon which regulators rely and the subsequent period of
17 time during which new utility rates are effective. Historical test periods necessarily
18 rely upon actual, recorded financial data that is at least several months old at the time
19 of rate hearings and may include data at the beginning of the period that is up to two
20 years old by the time a final order is issued. Advocates of the projected test period
21 approach claim that a significant benefit associated with the use of budgeted future
22 financial data is the ability to reduce regulatory lag by relying upon data that is more

1 representative of the cost and revenue environment expected while the new rates
2 would be effective. However, even the recent actual and estimated data used in
3 assembling projected test period revenue requirement calculations must be fixed at a
4 point in time for presentation before the Commission. The data is therefore subject
5 to regulatory lag and the financial circumstances faced by the utility continue to
6 change.

7 Regulatory lag is therefore an unavoidable characteristic of test period
8 regulation that can work to the advantage or disadvantage of the utility depending
9 upon how future actual revenue and cost trends compare to amounts used to
10 determine the revenue requirement. Symmetrical risks and opportunities arise for
11 utility ratepayers and shareholders as a result of regulatory lag because favorable and
12 unfavorable changes in revenue requirement can produce over or under-earning
13 outcomes until either the utility or some other party initiates a new rate case
14 proceeding.

15 **Q. Are any regulatory incentives created by the existence of regulatory lag?**

16 A. Yes. As discussed above, one obvious and desirable incentive created by regulatory
17 lag is that management is encouraged to control and minimize operating expenses
18 and capital expenditures at economically efficient levels so as to optimize achieved
19 earnings between rate cases. Unfortunately, management also faces an incentive to
20 attempt revisions to the traditional regulatory framework, either through legislative
21 initiatives or regulatory proceedings, in an effort to change the methods and
22 procedures through which cost of service changes can be translated into increased
23 revenues. The new tracking tariff riders for uncollectibles, accelerated plant

1 investment and for declining gas usage per customer trends now being proposed by
2 PGL and NSG are examples of efforts to “sweeten” the regulatory framework with
3 preferential ratemaking treatment for isolated elements of the overall revenue
4 requirement calculation. Each newly proposed rider would track (and counteract)
5 changes in a selected cost item (or revenue trend) that PGL expects will reduce its
6 future achieved return between test years. In other words, the riders uniformly
7 protect the interests of PGL and NSG, with no comparable mechanism to protect
8 the interests of their ratepayers.

9 **Q. How could creation of piecemeal tariff riders impact regulatory lag and the**
10 **efficiency incentive to utility management arising from regulatory lag?**

11 A. Tracking tariff riders can virtually eliminate the regulatory lag efficiency incentive,
12 by selectively changing utility rates to track changes in individual elements of the
13 revenue requirement calculation. For example, PGL’s plant investment ICR tracker,
14 if approved, would reduce the incentive faced by management to carefully plan and
15 manage capital expenditure levels between test years, because any increased plant
16 investment within eligible accounts, above historical average plant investment, can
17 be translated into piecemeal rate increases outside of a formal rate case proceeding.
18 Similarly, the proposed UBA tracker for uncollectible accounts shifts a portion of
19 the risks of bad debt experience toward customers, reducing management’s
20 financial incentive to carefully manage credit and collection policies. With regard
21 to the energy efficiency program funding, the amounts to be funded are fixed and
22 are known with certainty, so there is no need for a tariff rider to account for
23 changing expenditure levels. With respect to the VBA decoupling proposal, PGL

1 and NSG seek to track negative trends in usage on a per customer basis for certain
2 customer classes, even though overall gas margins have not been declining. I
3 discuss gas usage incentive concerns and efficiency incentives in a later section of
4 my testimony.

5
6 **III. EVALUATIVE CRITERIA FOR TRACKING RIDER TARIFFS**
7

8 **Q. You have described the regulatory concepts associated with traditional test**
9 **period regulation of public utilities. Are there instances where the traditional**
10 **test year approach does not produce reasonable results?**

11 A. Yes. In certain limited circumstances, it can be necessary to depart from the
12 balanced and synchronized review of all revenues and costs within the traditional
13 test year approach. These limited circumstances are described in this section of my
14 testimony.

15 **Q. Under what circumstances should regulators consider adopting tracking rider**
16 **tariffs and/or regulatory deferral accounting for specific changes that occur**
17 **between rate case test years?**

18 A. Rate tracker riders and cost deferrals should be approved only in instances where
19 compelling circumstances justify departure from traditional test period review of all
20 costs and revenues within rate case proceedings in which the overall revenue
21 requirement can be audited and considered in a balanced and synchronized manner.
22 Costs or revenue changes to be deferred or rate tracked through a rider should
23 generally have all of the following attributes to merit such exceptional and
24 preferential rate recovery treatment:

1. Substantial enough to have a material impact upon revenue requirements and the financial performance of the business between rate cases.
2. Beyond the control of management, where utility management has little influence over experienced revenue or cost levels.
3. Volatile and unpredictable in amount, causing significant swings in income and cash flows if not tracked.

Moreover, any adopted rate tracker rider should be straightforward and simple to administer, readily audited and verified through expedited regulatory reviews. Further, any approved rider must be carefully balanced and not distortive of test period relationships – accounting for any known factors that mitigate impacts in a manner that preserves test year matching principles. In the testimony that follows, I will apply these general criteria to the four proposed rate trackers being advocated by the Companies to demonstrate why these proposals should be rejected.

Q. Have any of these criteria been explicitly recognized by regulators in evaluating proposals for piecemeal rate tracking tariff riders?

A. Yes. In a recently completed electric rate case in Missouri, the Public Service Commission in that State rejected a proposed fuel adjustment clause tariff in an AmerenUE rate case after citing my testimony in that case and applying these criteria.⁸ In its Decision and Order, the MoPSC referenced the importance of test period “matching” and observed that AmerenUE fuel expenses were not sufficiently volatile to merit adjustment clause treatment and also noted that AmerenUE’s ability to engage in profitable off-system sales tends to mitigate the impact of future

1 fuel price increases that may be experienced by AmerenUE, implicitly recognizing
2 the fifth criteria stated above.⁹ Also, I am advised by counsel that the Illinois
3 Appellate Court reversed an Illinois Commission decision in which it approved rider
4 treatment for costs associated with demand side management programs and their
5 associated lost revenues, holding that the approved rider treatment constituted
6 illegal single-issue ratemaking.¹⁰

7 **Q. Has any witness for PGL and North Shore acknowledged the validity of the**
8 **evaluative criteria you suggest?**

9 A. Yes. In the response to Data Request No. AG 4.06, the Companies stated, “Mr.
10 Feingold believes that a ratemaking mechanism that provides for periodic rate
11 adjustments to recover certain base rate components should be considered as an
12 appropriate regulatory method when it addresses costs that are: (1) uncontrollable
13 by the utility; (2) variable and unpredictable; and (3) material in nature.” While Mr.
14 Feingold would probably apply these criteria more liberally than I believe is
15 appropriate, there is no apparent disagreement regarding the need for a showing of
16 large, volatile and uncontrollable characteristics before rate tracking tariff riders
17 should be considered.

18 **Q. Do regulated utilities in Illinois, if they experience significant attrition between**
19 **rate cases that compromises their financial strength, as a result of large and**
20 **volatile cost changes, have any options for regulatory relief other than**
21 **piecemeal rate tracking tariff riders or accounting deferrals?**

⁸ Report & Order Issued May 22, 2007; In the Matter of Union Electric Company d/b/a
AmerenUE’s Tariffs Increasing Rates for Electric Service, Case No. ER-2007-0002; pp. 15-27
⁹ Id, pp. 23-24.

1 A. Yes. In general, utilities are not restricted as to when they may petition the
2 Commission for rate relief. Illinois utilities are allowed interim rate relief when
3 facing very serious financial circumstances, if required factors are present.¹¹ In the
4 event PGL or NSG actually experiences serious attrition problems under traditional
5 regulation in the future, the Company may be able to qualify for interim rate relief
6 as a remedy for such problems.

7 **Q. Does the historical financial performance of PGL and NSG in Illinois indicate**
8 **any apparent problems with traditional regulation, such that extraordinary**
9 **rate tracking treatment is warranted based upon demonstrated financial**
10 **needs?**

11 A. No. The Companies have not requested a general rate case increase in Illinois since
12 1995, which is a strong indication that traditional regulation has been working
13 reasonably well and that the Companies' non-gas costs to provide utility service
14 have not been growing significantly faster than utility margin revenues (revenues
15 less gas costs). PGL's actual earned return on equity ("ROE") has been consistently
16 positive, staying within a range from 10.16 to 14.52 percent throughout the nine
17 year period 1995 through 2003.¹² More recently, PGL states its returns have
18 declined as described in the testimony of Mr. Borgard,¹³ and the alleged decline in

¹⁰ *A.Finkl & Sons Company v. Illinois Commerce Commission*, 250 Ill.App.3d 317, 620 N.E.2d 1141 (First Dist. 1993)..

¹¹ I am advised by counsel that Section 9-202(b) of the Illinois Public Utilities Act permits the Commission to grant interim rate relief when the Commission enters upon a hearing concerning the propriety of any proposed rate or other charge, classification, contract, practice, rule or regulation and the Commission finds that a hearing to determine all of the issues involved in a final determination of rates or services will require more than 120 days. Part 330.30 of the Commission's rules provide the necessary conditions that must be met by the utility for the Commission to grant interim rate relief.

¹² Peoples Gas response to Data Request No. AG.4.08.

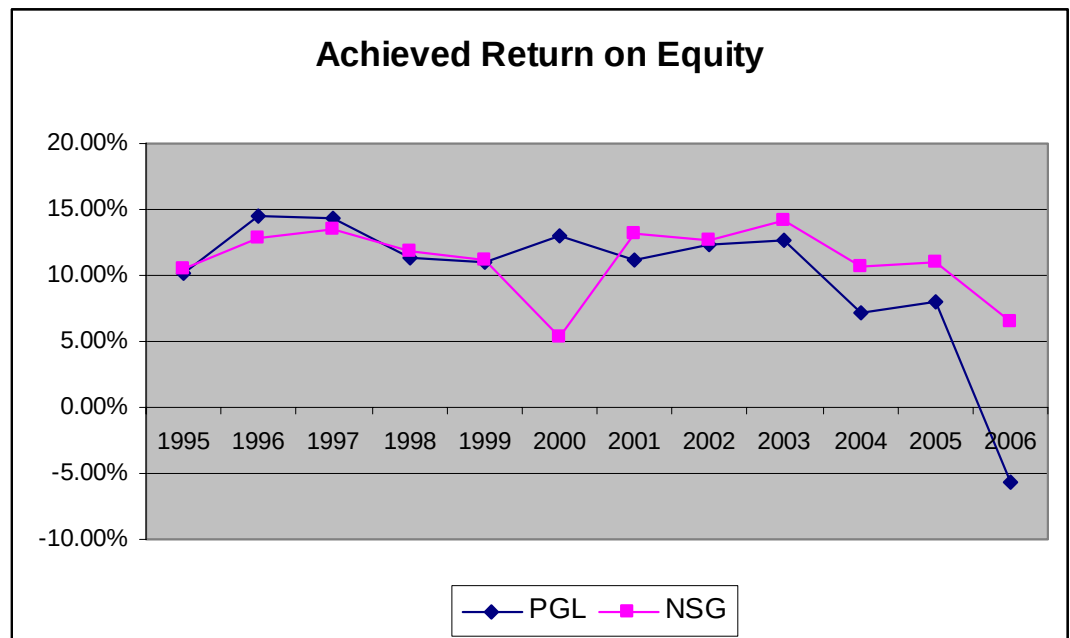
¹³ PGL Ex. LTB-1.0, page 9.

PGL earnings since 2003 has undoubtedly contributed to the Company's decision to pursue the pending rate increase request.

For North Shore, financial results under traditional regulation have been similarly stable, with ROE ranging from 10.43 to 14.13 percent in all years 1995 through 2005, except for the year 2000 when ROE was 5.38 percent.¹⁴ It appears that traditional test year regulation has served the Companies well with no apparent need for extraordinary forms of rate rider price increases between test years.

The following table summarizes historical achieved rates of return for the two utilities, indicating that traditional test year regulation without the piecemeal rate trackers now being proposed, has apparently provided an adequate opportunity for the utilities to consistently achieve a reasonable return on invested equity capital:

Table 1:



1 **Q. Have the Companies produced any evidence that recent changes in their**
2 **operations will preclude them from continuing to earn reasonable returns in**
3 **the future under traditional regulation, if the newly proposed rate rider tariffs**
4 **are not approved?**

5 A. No. PGL and North Shore have not provided any projected information that
6 indicates a need for extraordinary rate rider forms of additional future rate relief.
7 When asked in Data Request No. AG 4.05 whether the Companies have prepared
8 any projections of future financial performance with or without the benefits of
9 proposed Riders EEP, UBA, VBA or ICR, to evaluate the financial impact of any or
10 all of the proposed riders, the Companies responded “There are none.”

11

12 **IV. RATE TRACKING RIDERS SHIFT RISKS AND COSTS TO RATEPAYERS**
13 **WITH NO SHOWING OF NEED BY THE UTILITIES**

14

15 **Q. Is there a common theme associated with each of the proposed new tariff**
16 **riders that are addressed in your testimony?**

17 A. Yes. Each of the proposed riders, if approved by the ICC, would tend to translate
18 potentially negative operational trends or discrete expected future cost changes into
19 piecemeal rate increases to consumers.

20 **Q. How would Commission approval of the Companies’ proposed VBA**
21 **decoupling tracking tariff impact customers?**

22 A. The Companies’ VBA proposal promises generally higher prices for consumers,
23 with no demonstrated benefits for customers in the form of enforceable

¹⁴ North Shore Gas response to Data Request No. AG. 4.08.

1 commitments to not seek traditional rate increases in the future or to accept a lower
2 rate of return so as to recognize the shifting of sales volume risks to customers. Mr.
3 Feingold's Peoples Gas Ex. RAF-1.2 and North Shore Ex. RAF-1.2 illustrate the
4 long term historical declines in natural gas usage per residential customer with
5 projections of continued declines in such usage in the future. Rider VBA would
6 adjust pricing to customers to normalize for weather fluctuations, but would also
7 continuously translate this gradual negative usage trend (after weather
8 normalization) into piecemeal rate increases between test years, to the distinct
9 disadvantage of utility ratepayers. I will discuss in greater detail how the proposed
10 VBA would impact customers in a later section of this testimony.

11 **Q. How would Commission approval of PGL's proposed plant investment ICR**
12 **tracking tariff impact customers?**

13 A. PGL's proposed Rider ICR can only produce potentially higher prices for
14 consumers, with no corresponding demonstrated benefits. In its proposed form, any
15 growth in spending on mains, services and house regulators above historical
16 average levels would translate directly into higher future prices for consumers.¹⁵
17 These rate increases would occur outside of a rate case in which PGL would need to
18 also account for generalized productivity growth, any specific cost savings
19 associated with such higher capital spending and any other changes in its revenue
20 requirements. Mr. Schott's testimony states at page 4, "The amount recoverable

¹⁵ See Direct Testimony of Valerie H. Grace, PGL Ex. VG-1.0 at page 49, indicating that "Rider ICR will recover, on a per customer basis, costs associated with the accelerated replacement of cast iron and ductile steel main and connecting facilities, including services, meters and regulators." The corresponding tariff at PGL Ex. VG-1.1, pages 142-144 is structured to calculate only a "charge" and no credit if expenditures decline from historical levels.

1 under this Rider will be a function of any differences between the average of the
2 ‘baseline’ levels of capital expenditures of the Existing Replacement Program
3 during fiscal years 2004, 2005 and 2006, which fiscal years were the twelve month
4 periods ended September 30, and the actual capital expenditures.”

5 **Q. Would the uncollectible tracker UBA tariff also shift the risk of increasing**
6 **costs to customers while reducing regulatory lag efficiency incentives?**

7 A. Yes. Any increases in uncollectible accounts arising from changes in gas costs
8 would be recoverable outside of rate cases under the Companies’ proposed UBA
9 tariff. While this proposed cost tracking is more symmetrical than the VBA and
10 ICR proposals, since both favorable and unfavorable uncollectible cost changes
11 would be tracked, the risks associated with fluctuating commodity cost bad debts is
12 shifted to customers under this proposal.

13 **Q. What do these three alternative ratemaking tariff rider proposals have in**
14 **common?**

15 A. Each of the Companies’ proposed new rate trackers represent management’s
16 selection of isolated elements of the revenue requirement calculation, where future
17 changes are expected to have negative profit consequences to the utility, for
18 piecemeal rate changes that would shift costs and risks to ratepayers. These
19 regulatory “sweeteners” would distort the Illinois regulatory framework and would
20 systematically disadvantage ratepayers who are entitled to a more balanced
21 assessment of the overall cost of service when utility rates are changed.

1 **Q. In this section of testimony, you have not included the EEP Rider proposal.**
2 **Why is it excluded from your discussion of shifting of costs and risks to**
3 **ratepayers?**

4 A. The EEP is not intended to track a discrete element of the normal utility revenue
5 requirement on a piecemeal basis so as to reduce regulatory lag. Instead, Rider EEP
6 appears to be proposed as a funding mechanism -- a device to collect in advance
7 funding revenues intended for efficiency program expenditures and to reconcile
8 such revenues to actual spending levels. The efficiency program spending is
9 intended to be at a fixed annual amount that should be included within the base rate
10 revenue requirement, as more fully described later in this testimony.

11 **Q. Has PGL or NSG made any showing that it will need the additional future**
12 **revenues that may be created through VBA, UBA or ICR tracker piecemeal**
13 **rate increases in order to have a reasonable opportunity to earn the allowed**
14 **rate of return?**

15 A. No showing has been made that any known and measurable changes in future PGL
16 or NSG revenues or expenses would contribute to significant earnings deficiencies
17 that could not be sufficiently addressed under traditional regulation. The
18 Companies have not presented any attrition analyses or other studies to support the
19 premise that these extraordinary rate tracking tariffs are needed. Traditional Illinois
20 regulation has clearly served the Companies well financially, and PGL and NSG do
21 not offer any evidence indicating any known and measurable changes that merit
22 changing the regulatory framework prospectively. Other than speculation
23 regarding possible economic benefits associated with an Accelerated Program for

1 future PGL capital spending on main replacements, above the Existing Replacement
2 Program described in Mr. Schott's testimony, no evidence of known and
3 measurable financial changes has been presented.¹⁶

4 **Q. If the Commission approves the VBA, UBA and plant investment ICR**
5 **trackers, will operating risks normally borne by shareholders be shifted to**
6 **ratepayers?**

7 A. Yes. Any future increases in PGL plant investment above historical averages,
8 which would normally be borne by shareholders between rate case test years, would
9 instead be tracked through rate changes to be funded on a piecemeal basis by
10 ratepayers. Similarly, if weather normalized gas usage per customer declines
11 between test years, PGL and NSG would increase rates to shift such risk to their
12 customers on a piecemeal basis. If gas commodity prices increase in the future,
13 any growth in uncollectible accounts caused by such price changes would be borne
14 by customers instead of shareholders.

15 **Q. Has the Commission previously authorized rate tracking mechanisms that**
16 **benefit PGL and NSG shareholders by shifting the risks arising from large and**
17 **volatile cost changes to ratepayers?**

18 A. Yes. The Companies are already insulated from significant risks associated with
19 potentially large and volatile changes in purchased gas costs through its
20 Commission-approved PGA mechanism. Additionally, I understand that a Rider 11
21 Tariff exists to track and recover costs incurred by the Companies in connection
22 with certain costs of remediation of manufactured gas plant sites. I believe the

¹⁶ Peoples Gas Ex. No. JFS-1.0), pages 4-12.

1 Companies are over-reaching in this case, by seeking additional new rate tracking
2 mechanisms to further transfer their operational risks onto ratepayers.

3
4 **V. COMPLEXITY AND ADMINISTRATIVE BURDENS**

5
6 **Q. How do tracking tariffs generally impact regulatory complexity and**
7 **administrative costs?**

8 A. The addition of tracking tariff riders adds complexity to regulatory processes in
9 several ways. First, each new tracking tariff creates incremental new regulatory
10 reporting in support of periodic price changes that must be created by utility
11 company staff and then reviewed by Commission Staff personnel. Then, it may be
12 necessary for Commission Staff to organize and conduct audits of the financial data
13 underlying the filings, since customer prices are directly impacted by such data. If
14 any disputes arise from either informal review procedures or more comprehensive
15 audits, it may be necessary to develop formal discovery and dispute resolution
16 procedures. When applicable review procedures are completed, the utility must
17 implement the rate change along with any customer disclosures that may be
18 required and then be ready to respond to customer inquiries arising from rate
19 changes. Unfortunately, because tracking tariffs are designed to facilitate expedited
20 rate changes, the process just described must often occur within a compressed
21 timeline that can frustrate efforts for thorough review and/or contribute to increased
22 costs to the utility, the regulatory agency, intervenors and customers.

1 **Q. Is it reasonable to expect that utility company employees and ICC Staff**
2 **personnel would be burdened with significant additional work if the VBA**
3 **decoupling tariff were adopted?**

4 A. Yes. Company witness Ms. Grace describes the monthly filings and calculations
5 that are proposed to administer Rider VBA, indicating the need to report and
6 calculate changes in actual customer and usage levels relative to a “baseline”
7 distribution margin per customer for each of three rate classes.¹⁷ The inherent
8 complexity of these calculations can be seen in the proposed tariff for Rider VBA,
9 which contains formulae to calculate an “Effective Component” as well as a
10 “Reconciliation Adjustment” with interest added to any reconciliation balances.¹⁸
11 Reports to be prepared to support the monthly calculated changes to the VBA Rider
12 rates are set forth in eight pages of information sheets for each of the two
13 Companies.¹⁹ Given the importance of the calculations to customers’ rates, ICC
14 Staff personnel would need to review and audit such calculations. Out of apparent
15 concern regarding the Staff’s audit burden associated with the VBA, Staff
16 propounded Data Request No. DLH 2.12, asking the Companies to agree to add a
17 provision to any VBA Rider that would “require an annual internal audit of the
18 annual statement of the Reconciliation Adjustment RA₁ and RA₂ of the VBA Rider
19 for each Company”, and in their response, the Companies agreed to add such a
20 provision.

21 **Q. Have the utilities acknowledged any administrative burden or cost arising**
22 **from the addition of monthly VBA Rider rate adjustments?**

¹⁷ Peoples Gas Ex. VG-1.0, pages 46-48; North Shore Ex. VG-1.0, pages 42-44.

1 A. No. In AG Data Request No. 3.09, the Companies were asked for their “best
2 estimate of annual administrative and regulatory costs to be incurred if the revenue
3 decoupling mechanism is approved by the Commission and implemented by them”
4 and the Companies responded that they “...do not anticipate any incremental
5 administrative or regulatory costs to be incurred” and that “the Company is unable
6 to determine whether the Commission Staff would incur any additional costs if the
7 revenue decoupling mechanism were approved.

8 I do not agree with the Companies’ optimistic view that no incremental
9 administrative costs would result from implementing the proposed VBA tariff.
10 Even if the VBA proved ultimately to be as simple and non-controversial to
11 administer as PGL and NSG expect, any regulatory complexity and burden added
12 by the VBA would compound the regulatory administration burden and costs
13 already arising from the Company’s PGA and would be simple and straightforward
14 only if no significant disputes arose over implementation details. While in
15 isolation, PGL and NSG may not anticipate the VBA to add any significant time
16 commitment for ICC Staff, it would be entirely reasonable for the Commission to
17 consider any added burden as cumulative to all other proposed rate Riders as well
18 as any tariff riders that now exist or may be proposed by other regulated utilities if
19 expanded tracking becomes accepted ICC policy.

20 **Q. Would the proposed plant investment ICR Rider, if approved, also add to the**
21 **cumulative administrative burden upon the utility and the ICC Staff?**

¹⁸ PGL Ex. VG-1.1, pages 57-60, NSG Ex. VG-1.1, pages 55-58.
¹⁹ PGL Ex. VG-1.16; NSG Ex. VG 1.15.

1 A. Yes, for the same reasons discussed above with respect to the VBA Rider
2 mechanism. The administrative complexity of the ICR Rider is evident from the
3 complex “Section C – Determination of Charges” formulae and the multiple defined
4 input values to be determined and calculated on an annual basis.²⁰ If any prudence
5 review is required before new plant investment is chargeable to customers, the
6 administrative burden associated with the ICR Rider may be quite significant with
7 each ICR filing made. If such a review is foregone, customers lose the protection of
8 a significant element of regulatory oversight. Later in this testimony I discuss in
9 greater detail the mechanical problems and other inconsistencies associated with the
10 specific formulae proposed for use in administering Rider ICR.

11 **Q. If the proposed Riders UBA and EEP are also approved for the two utilities, is**
12 **it reasonable to expect that the utilities, the ICC Staff and any interested**
13 **customer representatives would face an incremental administrative burden?**

14 A. Yes. Additionally, if such piecemeal rate change tariff riders are approved for PGL
15 and NSG, it is reasonable to expect other regulated utilities in Illinois to also
16 propose piecemeal rate tracking tariff riders that would be advantageous to their
17 shareholders, which would further contribute to statewide regulatory burdens.

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²⁰ See Peoples Gas Ex. VG-1.1 at pages 142-144. Rider ICR would compare total actual capital spending each year within five different “Plant Investment (PI)” accounts to average historical investment in each of the accounts in the years 2004, 2005 and 2006 to determine a “Plant Investment Increment (PII)” in each year. Then calculations of depreciation expense on only this incremental investment is subtracted, with the net incremental investment then multiplied by a pretax rate of return and a depreciation accrual rate pursuant to the formulae set forth at page 3 of the Rider.

1
2 **VI. RIDER VBA - DECOUPLING**
3

4 **Q. At pages 13 through 36 of his testimony, Mr. Feingold describes the**
5 **Companies’ proposed decoupling mechanism, which has been labeled a**
6 **“Volume Balancing Adjustment Rider” or “VBA”. What reasons are**
7 **advanced by Mr. Feingold in support of this new Rider?**

8 A. Mr. Feingold argues that certain “business challenges” are faced by gas utilities in
9 general and by Peoples Gas and North Shore, including sales margin variability
10 caused by weather fluctuations and declining use per customer due to
11 conservation.²¹ He describes how “margin revenues” are quantified in rate case test
12 year calculations, to provide recovery of what Mr. Feingold characterizes as mostly
13 fixed costs. Then in subsequent years, the actual margin revenues the utility
14 collects vary due to weather and generally decline on a per customer basis due to
15 conservation trends.²² He observes at page 19 of his PGL testimony that, “Several
16 factors influence the level of customer gas usage, including weather variation, the
17 level of wholesale gas prices, and the effects of conservation measures, including
18 the impact of energy efficiency gains on customer use.” After noting in his Peoples
19 Gas Ex. RAF-1.4 and North Shore Ex. RAF-1.4 how margin revenues for certain
20 customer classes have generally declined as a result of usage per customer trends
21 since the last rate case, Mr. Feingold claims at page 21 that:

22 The proposed Rider VBA will minimize the impact of weather on
23 [Peoples Gas’ / North Shore’s] financial condition and on the
24 volatility of its customers’ bills. The proposed Rider represents the

²¹ PGL Ex. RAF-1.0, pages 6-7 and page 13. NSG Ex. RAF-1.0, pages 5-7 and page 12.
²² Id, pages 15-19 for PGL, 13-17 for NSG.

1 required fundamental change to the utility ratemaking process to
2 recognize that a utility such as [Peoples Gas/North Shore] has
3 difficulty in establishing a reasonable level of volumes in a rate case
4 that can represent its volumes in future periods.
5

6 Mr. Feingold also advances other arguments in favor of the new Rider VBA rate
7 proposal, including:

- 8 • Proposed Rider VBA will remove the disincentive to promote energy
9 conservation and efficiency programs for its customers. (PGL pages 22-23)
- 10 • Other gas utilities are proposing and implementing “solutions” such as
11 weather normalization adjustment clauses or revenue decoupling
12 mechanisms. (PGL page 21)
- 13 • Certain industry groups have endorsed the “concept of decoupling”. (PGL
14 pages 26-29)
- 15 • Some state regulators have approved the “concept of revenue decoupling”.
16 (PGL page 30)
- 17 • The financial community has acknowledged that decoupling is favorable to
18 LDC’s and their credit ratings. (PGL page 31)
- 19 • The impact of proposed Rider VBA upon customers’ bills will be
20 “minimal”. (PGL page 35)

21 In this section of my testimony, I will respond to these claims and explain why
22 Rider VBA is not appropriate and should be rejected by the Commission.

23 **Q. Has Mr. Feingold or any other Company witness sponsored evidence to**
24 **support a conclusion that Rider VBA is needed in order for either utility to**
25 **earn reasonable future returns?**

1 A. No. Mr. Borgard also testifies in support of the VBA proposal, stating, “The
2 Company needs to decouple its cost recovery from the volumes used by customers,
3 particularly with respect to non-usage sensitive costs of service, if it is to have any
4 chance of earning a reasonable return and thereby maintain its ability to provide
5 safe, adequate, and reliable service to customers in an increasing energy efficient
6 environment.”²³ While it is reasonably expected that Rider VBA will increase
7 future margin revenues for both utilities if approved, as long as gradual
8 conservation trends continue and weather conditions fluctuate around average
9 normal conditions, there has been no showing by either Company that such
10 additional revenues are needed in order for the Companies to have a reasonable
11 opportunity to earn the authorized return levels.

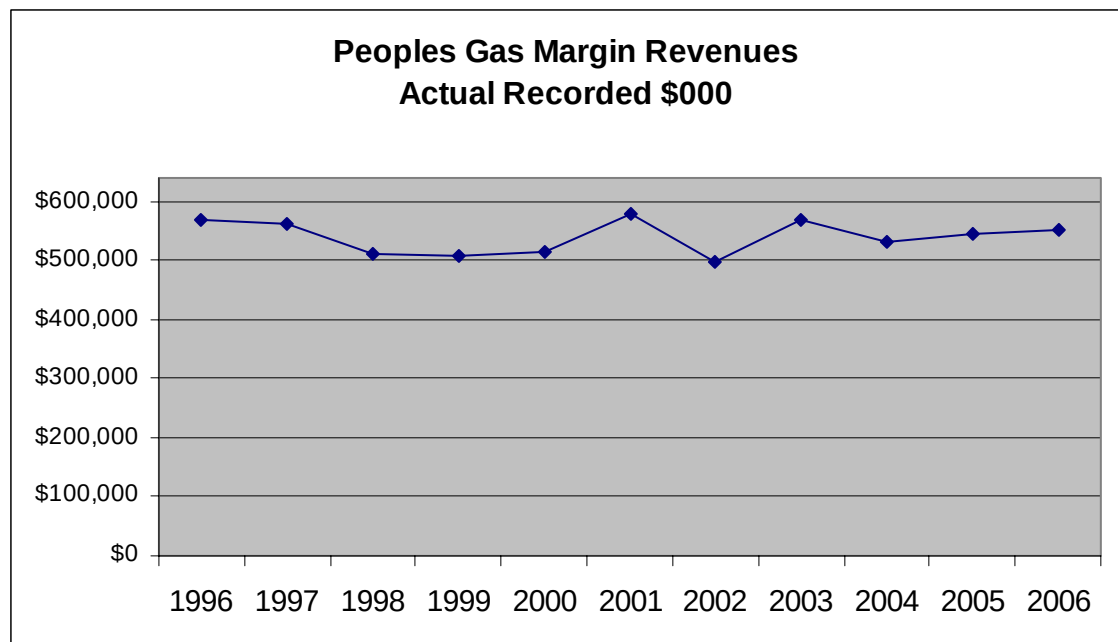
12 **Q. Has Peoples Gas Company or North Shore Gas experienced declining overall**
13 **margin revenues (revenues less gas costs) as implied in the companies’**
14 **testimony?**

15 A. No. Mr. Borgard sponsors an Exhibit LTB-1.2 for each utility and an Exhibit LTB-
16 1.3 for PGL that indicates declining usage per small residential customer and per
17 PGL Rate 2 Customer since 1994. Mr. Feingold’s Exhibit RAF-1.4 for each utility
18 also implies declining margin revenues. However, Mr. Borgard and Mr. Feingold
19 are careful to discuss such gas usage and margin trends on a “per customer” basis,
20 limiting the discussion to only the small residential and commercial classes, but the
21 reality is that PGL and NSG overall gas margins are not systematically declining.
22 Total gas margin revenues are influenced by more variables than simply residential

²³ Peoples Gas Ex. LTB-1.0, page 23; North Shore Ex. LTB-1.0, page 21.

and small commercial usage per customer, including the number of customers served within each rate schedule, overall economic conditions and other factors. A more balanced and accurate depiction of overall margin revenue trends can be observed in the following graph of actual margin dollars recorded by PGL in each year from 1996, when base gas delivery rates were last changed, through fiscal 2006:

Table 2: PGL Gas Margins



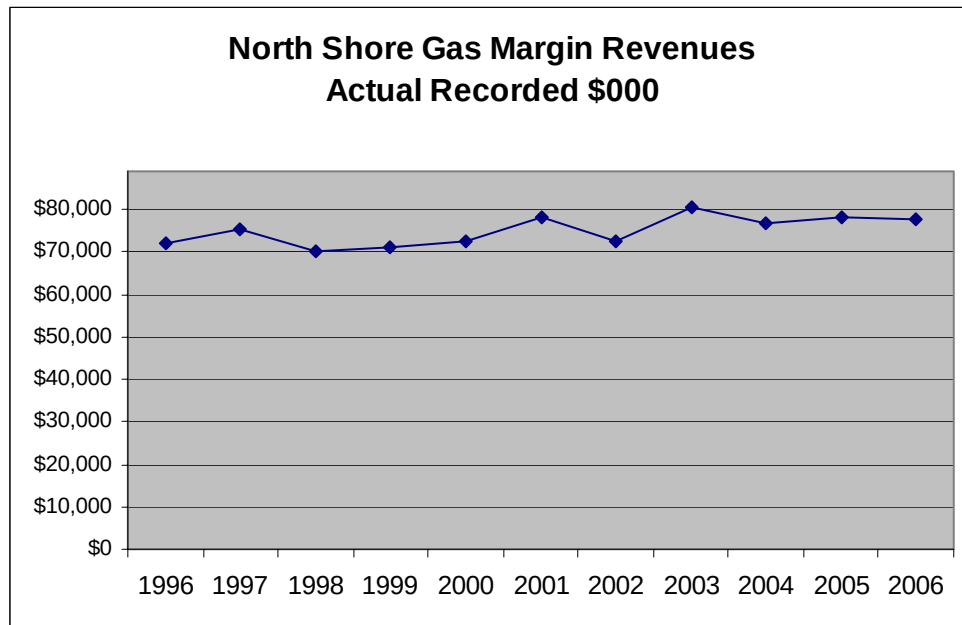
Source: PGL response to Data Request AG 4.04

The actual recorded annual PGL margin revenues have been relatively stable in overall terms for the past 11 years, ranging from a low of \$498 million in 2002 to a high the year before, in 2001, of \$577 million. Average margin revenues throughout this period were \$540 million and margin fluctuations from year to year

1 due to weather and other causes were always within \$42 million or 8 percent of this
2 average amount.²⁴

3 North Shore Gas margin revenues are also not declining in overall terms,
4 as implied by Mr. Borgard and Mr. Feingold, but have actually been trending
5 upward from 1996 through 2006:
6

7 **Table 3:**



8
9 Source: PGL response to Data Request AG 4.04

10 Recorded annual North Shore margin revenues have been trending gradually
11 upward for the past 11 years, ranging from a low of \$70.2 million in 1998 to a high
12 in 2003 of \$80.6 million. North Shore witness Borghard acknowledges the fact that
13 North Shore's service area is one of the fastest growing areas in Illinois.²⁵ Average

²⁴ The largest departure from average margins was in 2002, when actual margin revenues were \$498 million.

²⁵ Borghard Direct, p. 13.

margin revenues throughout this period were \$75.0 million and margin fluctuations from year to year due to weather and other causes were always within \$5.6 million or 8 percent of this average amount.²⁶

Q. Does the actual trend in margin revenues experienced by PGL and NSG reveal an important deficiency in the VBA proposal being advanced by the Companies' witnesses?

A. Yes. The Companies' VBA proposal is hopelessly piecemeal, seeking to adjust future utility prices for anticipated declines in usage per customer for selected customer classes, while ignoring overall margin revenue stability or, in the case of North Shore, generally favorable margin trends. Gas utility margin revenues are a function of both the number of customers being served and the average usage levels of such customers in all customer classes. Clearly the addition of new customers by PGL and to a larger extent by NSG, as well as all other influences upon achieved gas margin income tends to offset most or all of the declining usage "per customer" that Messrs. Borgard and Feingold have chosen to emphasize.

Q. At page 11 of his PGL testimony, Mr. Borgard states, "Further, the reduced usage per customer has not been offset by the increase in the number of residential heating customers served by the Company." How can this be true if overall margin revenues for PGL, as shown in your Table 1, are not declining?

A. Apparently, the key phrase in Mr. Borgard's statement is his use of the restriction to limit the increased number of customers to only "residential heating customers".

²⁶ The largest departure from average margins was in 2003, when actual margin revenues were \$80.6

Clearly, when viewed more broadly in Tables 2 and 3 above, customer growth and other drivers of overall margin revenues are offsetting the declines in residential usage per customer that would be addressed by proposed Rider VBA.

Q. Mr. Feingold’s NSG and PGL Exhibit RAF-1.4 also depicts negative “margin variance” amounts in the million of dollars for North Shore and in the tens of millions of dollars for Peoples. How can these graphs be reconciled to the much more favorable total margin revenue trends you show in your Table 2 and Table 3, above?

A. It appears that Mr. Feingold has also chosen to narrowly focus his calculations upon volumetric changes per customer within selected rate classes, rather than evaluating the Companies’ overall actual margin revenue trends, as shown in my Tables 2 and 3, above. Mr. Feingold states that he prepared Exhibit RAF-1.4 to illustrate how the “baseline use per customer level” established by the Commission in the Companies’ last rate cases were “not representative of [the utilities] expected future trends”.²⁷ Mr. Feingold clearly states his preference that, “The reference point should be the use per customer levels established in [Peoples Gas’/North Shore’s] last rate case...”²⁸, but this is an unreasonably narrow “reference point” for the analysis of overall margin revenue trends that are actually being experienced by these utilities.

Q. At page 16 of his testimony, Mr. Feingold states that it is important for a utility such as Peoples Gas or North Shore Gas to actually realize the margin revenue

million.

²⁷ Peoples Gas Ex. RAF-1.0, page 19; North Shore Ex. RAF-1.0, page 17.

²⁸ Id. page 18.

1 **that was allowed by the regulator in the utility’s most recent rate case. Do you**
2 **agree with this statement?**

3 A. No. I disagree with the suggestion that any specific dollar amount of approved
4 margin revenue in a rate case or any resulting margin revenue per customer amount
5 should be guaranteed revenue for the utility. All of the ratemaking input values will
6 change in the future; test year expenses will change, the cost of capital will change
7 and test year rate base values are not expected to remain constant after completing a
8 rate case. Changes in all of these values, some favorable and some unfavorable,
9 will impact earnings after the test year. The dynamic nature of the inputs to
10 revenue requirement calculation is precisely why traditional regulation imposes the
11 structure of a test year that is prepared on an internally consistent “matched” basis.

12 **Q. According to Mr. Feingold, “The utility’s financial health is directly tied to its**
13 **ability to recover the total cost of service (excluding purchased costs) approved**
14 **by its regulator through the margin revenues upon which its base rates were**
15 **previously established.”²⁹ Does the form of decoupling proposed in Rider VBA**
16 **“lock in” the test year approved margin revenues?**

17 A. No. Even if approved levels of margin revenues from the pending rate cases were
18 intended by the Commission to be fixed after a rate case (which they are not), it is
19 quite apparent that Mr. Feingold and the Companies are not proposing complete
20 revenue decoupling. Instead, the Companies intend to retain any future margin
21 growth arising from serving new customers or from other factors for the sole benefit

²⁹ Peoples Gas Ex. RAF-1.0, page 16; North Shore Ex. RAF-1.0, page 14.

1 of shareholders between rate cases, while changing prices through the VBA to
2 account for any changes in usage “per customer” that may occur in the future.

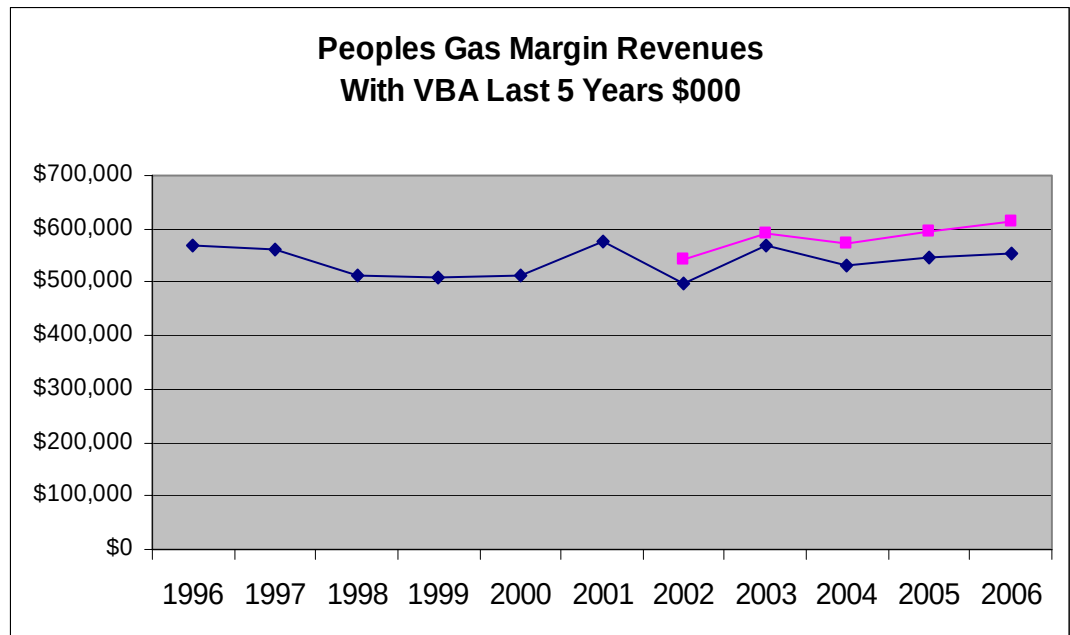
3 **Q. Have the Companies produced any illustrations of revenue effects that would**
4 **have occurred if the VBA Rider had been approved in the last rate case for**
5 **each utility?**

6 A. Yes. In response to Data Request No. AG 3.06, the Companies provided a back-
7 casting analysis showing how the proposed Rider VBA would have impacted
8 margin revenues if it had been in place over the past five fiscal years 2002 through
9 2006. The value of Rider VBA to shareholders and the cost to ratepayers is clearly
10 illustrated by these calculations performed by the Companies. Incremental Rider
11 VBA revenues would have provided an additional \$218 million to Peoples Gas
12 pretax operating income over the past five years and an additional \$24 million to
13 North Shore pretax operating income. These responses show that ratepayers would
14 have paid much higher rates if the companies’ proposed decoupling mechanism had
15 been in place, with margin rate increases growing to about 11.2 percent for PGL
16 and 8.9 percent for NSG by 2006.³⁰ I have attached copies of the Companies
17 responses to these data requests as GCI Exhibit MLB-1.3.

18 **Q. In prior testimony, you provided graphs captioned Table 2 and Table 3,**
19 **showing actual recorded PGL and NSG gas margin revenues over the past 11**
20 **years, respectively. How would the additional Rider VBA margin revenues**
21 **have impacted recorded margins if the new Rider had been in effect over the**
22 **past five years, using the Companies’ calculations in GCI Exhibit MLB-1.3?**

1 A. The incremental Rider VBA revenues would have significantly shifted actual
2 Peoples Gas margin revenue as indicated in the following graph:

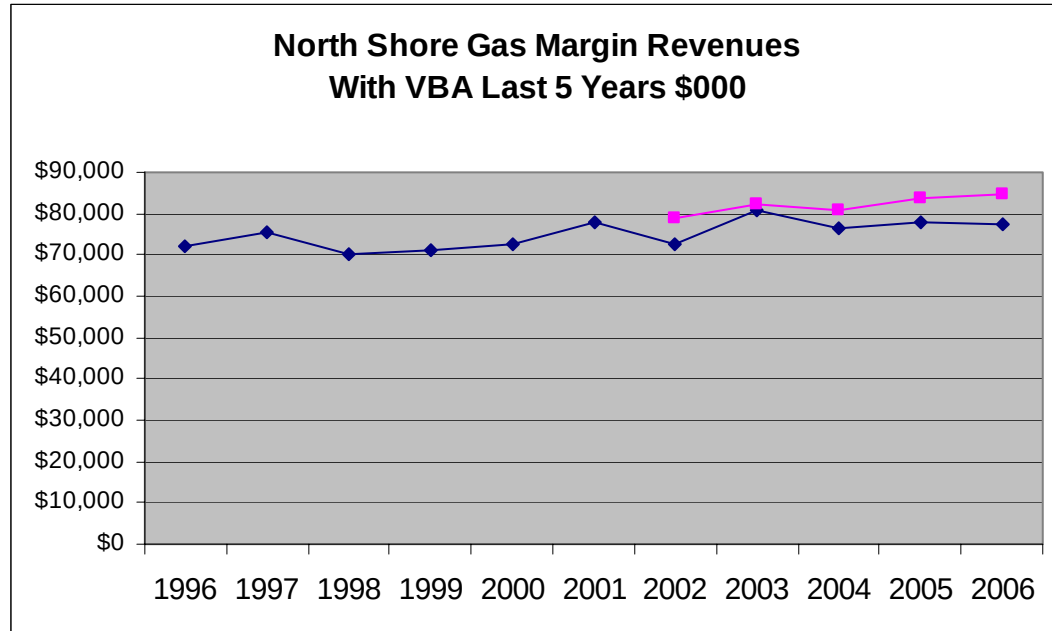
3 **Table 4:**
4



30 According to the PGL response to AG Data Request No. 3.06 the total “VBA impact” in FY 2006 would have been \$61.9 million if the Rider had been effective in that year, while for North Shore the “VBA impact” would have grown to \$6.9 million by 2006.

A similar up-shift would have been realized for North Shore's margin revenues:

Table 5:



As noted previously, the Companies have provided no specific evidence of financial need in support of the proposed Rider VBA, which would systematically increase margin revenues between rate cases if declining residential and small commercial per customer usage trends continue.

Q. With regard to the evaluative criteria for exceptional piecemeal rate tracking you defined earlier, are the expected margin revenue impacts arising from proposed Rider VBA large enough to satisfy the criterion involving the financial importance of the amounts involved?

A. No. The proposed VBA can be expected to produce relatively large cumulative revenue impacts if it remains in place for many years between rate cases, but the change in revenues in individual years is not particularly large. If we refer to the back-casting analysis in the immediately preceding answer, the largest annual

margin dollar change from the back-casted VBA illustration, assuming implementation in 2002, was a margin revenue change of \$21.7 million (from \$43.9 million to \$22.3 million) for PGL and \$4.5 million (from \$6.0 million to \$1.6 million) for North Shore in 2003.³¹ Annual margin changes in other years were generally smaller. These amounts, after reduction to account for income and revenue taxes of about 40 percent³², are significant but not particularly large in relation to the total test year operating income proposed by PGL of \$108 million at proposed rate levels and \$16.9 million for NSG at proposed rate levels.³³ Rider VBA is not obviously consistent with the first evaluative criterion I describe for piecemeal rate tracking, that its impact be substantial enough to have a material impact upon revenue requirements and the financial performance of the business between rate cases. Notably, looking solely at margin revenue changes does not indicate that earnings were necessarily impacted because of the reasonable expectation that productivity gains and changes in other costs could mitigate any margin changes between years.

Q. Does Rider VBA satisfy the second evaluative criterion for exceptional rate tracking that considers the volatility of changes impacting utility earnings?

A. While there is clearly some margin revenue volatility caused by weather, I do not believe Rider VBA clearly meets the volatility criterion. First, a review of actual historical recorded margin revenues for PGL and NSG in Tables 2 and 3 does not

³¹ See GCI Exhibit No. MLB-1.3.

³² PGL Schedule A-2.1 sets forth State Income Taxes of 7.3 percent and Federal Income Taxes of 35%, applied to taxable income after deducting the State Income Tax, which yields a composite effective income tax rate of 39.7 percent. Thus, a PGL pretax margin income change as large as \$21.7 million would impact operating income by about \$13 million or 12 percent of Company-proposed income levels.

1 reveal unacceptable levels of volatility in experienced margin revenues over the
2 past 11 years. These tables show fluctuations in margins from year to year,
3 probably due in large part to weather fluctuations, but relative stability over
4 multiple years. Similarly, the magnitude of changes in annual VBA adjustment
5 amounts assuming implementation in 2002, as shown in GCI Exhibit MLB-1.3,
6 does not suggest that the rider is needed to address revenue volatility concerns.
7 Tables 4 and 5 above, illustrating the back-casting impacts of proposed Rider VBA,
8 show the rider does not effectively eliminate margin fluctuations during the prior
9 years that are modeled.

10 **Q. If the Commission were concerned about margin revenue changes caused by**
11 **weather fluctuations, should the proposed VBA Rider be approved?**

12 A. No. The VBA is scoped much more broadly than is required to accomplish weather
13 normalization adjustments. If a weather normalization adjustment clause (“WNA”)
14 is desired, such a clause would be symmetrical and would tend to benefit customers
15 and shareholders. In contrast, the VBA is not a reasonable response to concerns
16 about symmetrical weather fluctuations around normal conditions because the VBA
17 is overly broad and would systematically increase rates for all changes in usage per
18 customer, including but not limited to weather fluctuations. Moreover, as discussed
19 above, tracking margin revenues on a per customer basis and then adjusting prices
20 to lock in such margins is an arbitrary metric that ignores overall revenue and
21 expense changes, to the benefit of the companies and the financial detriment of
22 ratepayers.

³³ See Schedule C-1, page 1 of the Section 285 filings of each utility in column K at line 24.

1 **Q. Does the proposed Rider VBA satisfy the third evaluative criterion you suggest**
2 **for piecemeal rate trackers, that the changes tracked in a proposed rider are**
3 **beyond the control of management?**

4 A. For this criterion, I would conclude that changes in residential and small
5 commercial gas usage per customer between rate cases, due to either weather or
6 conservation, are primarily beyond the control of management. However, my
7 opinion on this second point appears to differ from Mr. Feingold's. He argues that
8 Rider VBA is needed to "remove the disincentive Peoples Gas has to promote
9 energy conservation and efficiency programs for its customers" – implying that
10 management does exert some control over customer usage levels.³⁴ If the
11 Commission agrees with Mr. Feingold's concern about conservation disincentives
12 and finds that customer usage levels are within the control of utility management,
13 the need for Rider VBA to track gas usage changes is not justified under the
14 "beyond the control of management" criteria.

15 **Q. Do you dispute that it is necessary to provide rate tracking for declining usage**
16 **per customer and related margins in order to promote conservation?**

17 A. Yes. For many years residential and small commercial gas usage per customer has
18 been subject to the gradual cumulative effects of conservation, as well as many
19 other variables impacting natural gas demand, which include:

- 20 • changes in consumer preferences (cooking, lighting, laundry, etc.),
- 21 • replacement of older, less efficient gas appliances and furnaces,
- 22 • tighter and more efficient residential and commercial building designs,

³⁴ Peoples Gas Ex. RAF-1.0 at page 22; North Shore Ex. RAF-1.0, page 20.

- overall economic conditions, and
- consumer responses to changes in gas prices (elasticity).

As noted above, many factors affect actual margin revenues, and usage per customer is only one of the two main variables impacting such margin revenues – the other input being the number of customers being served. With so many factors impacting overall gas demand and margin income levels, it is unreasonable in my view to isolate only usage per customer changes thought to represent conservation effects for piecemeal rate tracking. No dramatically changed facts or circumstances now support elimination of normal test year ratemaking that sets gas delivery rates based upon test year normalized sales volumes, allowing productivity gains elsewhere in the business to offset the gradual effects of changing sales volumes.

Q. Is there any evidence that the Peoples/North Shore decoupling proposal would lead to increased energy efficiency investment by either the Company or ratepayers?

A. No. In concept, the Companies' proposed Rider VBA will only make the utility indifferent regarding the promotion of conservation and energy efficiency efforts. Conspicuously absent from the Companies' testimony is any suggestion, let alone a specific proposal, that they will invest more dollars in energy efficiency programs if Rider VBA is approved. Moreover, outside of an agreement to contribute \$5 million to energy efficiency measures arising out of a settlement in a case resolving the reconciliation of purchase gas adjustment clause revenues³⁵, and a separate agreement in the recent merger settlement to spend a combined Peoples/North

1 maximum of \$7.5 million on an energy efficiency program to be administered by a
2 third party governance board³⁶, neither Company has any history of promoting or
3 designing significant energy efficiency programs for its residential customers. In
4 fact, according to the terms of the merger settlement agreement in ICC Docket No.
5 06-0540, the Companies agreed to implement energy efficiency programs only “at
6 the funding levels that the Commission approves, and for which it provides cost
7 recovery, either in base rates or a rider, in the rate case orders.”³⁷ Given that the
8 two Companies have limited their proposals in this case for the implementation of
9 energy efficiency programs to the \$7.5 million agreed to in the merger settlement,
10 there simply is no reason to believe that the utilities will invest more in energy
11 efficiency programs if Rider VBA is implemented.

12 In addition, neither Mr. Feingold nor Mr. Borgard addresses the question
13 of how implementation of Rider VBA will affect customer incentives to conserve
14 energy and utilize energy efficiency measures on their own. Rider VBA, in effect,
15 punishes Peoples and North Shore customers by raising future per therm charges on
16 a monthly basis when customers conserve and reduce future margin revenue-per-
17 customer below a threshold level set in this docket. I believe it is fair to assume
18 that the incentive for customers to lower their thermostats, invest in more energy
19 efficient appliances and weatherization measures, and participate in any company-
20 sponsored programs will be diminished if Rider VBA is adopted.

³⁵ ICC Docket No. 00-0720, 01-0707, 02-0727, 03-0705, 04-0683, 00-0719, 01-0706, 02-0726, 03-0704, 04-0682, Settlement Agreement and Release, p. 5.

³⁶ ICC Docket No. 06-0540, Memorandum of Agreement, pp. 3, 4.

³⁷ Memorandum of Agreement, ICC Docket No. 06-0540, p. 4.

1 **Q. Does regulatory lag create a problem, by encouraging gas utilities to grow**
2 **demand or by discouraging conservation of energy?**

3 A. Not significantly. While it is true that utility shareholders will generally benefit
4 when sales volumes increase between test periods and are harmed when sales
5 decline, overall sales volumes are influenced by the addition of new customers as
6 well as by changes in usage levels of existing customers. In this era of higher-
7 priced natural gas, utilities have no choice but to support energy efficiency
8 measures as necessary to attract new customers and to retain existing gas utility
9 customers that may otherwise elect alternative energy sources such as electricity
10 when appliances are being installed or replaced.

11 **Q. Mr. Borgard has attached the “Conditions of Approval” for the Companies’**
12 **merger with WPS Resources Corporation as Exhibit LTB-1.6. Is it significant**
13 **that condition number 29 requires that “A third party administrator will**
14 **implement any energy efficiency program(s)” that are required to be funded**
15 **by the Companies in the pending rate cases?**

16 A. Yes. Third party administration causes the effectiveness of conservation programs
17 to be beyond the control of utility management. Any potential concerns about the
18 alleged utility “disincentive” to support conservation under traditional regulation, as
19 suggested by Mr. Feingold, is therefore inapplicable and not relevant to PGL or
20 NSG because of the third party administration provision within the merger
21 Conditions.

1 **Q. You explained in prior testimony how Rider VBA would add administrative**
2 **complexity and costs that should be considered by the Commission. Isn't this**
3 **true of any new tariff rider?**

4 A. Yes. This evaluative criterion would require a balancing of administrative
5 practicality with the relative importance of and need for the newly proposed rider.
6 It is important that any rider that would change prices to consumers on an expedited
7 basis be readily calculated, audited and confirmed as reasonable and also be easily
8 understood and accepted by customers. Rider VBA involves significant added
9 regulatory complexity that is not warranted, given the lack of demonstrated
10 financial need for the rider and Rider VBA's anticipated performance relative to the
11 other criteria discussed herein. As noted earlier, the concept of automatically
12 raising prices to make the utility "whole" when customers conserve may prove
13 difficult to explain to customers who expect to save money when investing in
14 conservation or when electing to dial-back their thermostats.

15 **Q. How does the proposed Rider VBA perform under your fifth evaluative**
16 **criterion, which requires consideration of offsetting or mitigating factors?**

17 A. The proposed Rider VBA fails this evaluative criterion because it does not account
18 for the mitigating impact of customer growth and other changes in margin revenues
19 that have tended to offset declining margin revenues arising from conservation (see
20 Tables 2 and 3, above). The VBA also fails to account for the fact that both utilities
21 have been able to operate successfully for more than 10 years since their last rate
22 case and without any rate tracking for declining usage per customer. This fact is a
23 clear indication of the existence of productivity effects and other variables that tend

1 to mitigate the long-standing downward trend in usage per residential customer that
2 has been experienced historically.

3 **Q. In your opinion, does the Companies' proposed Rider VBA properly balance**
4 **the interests of shareholders and customers?**

5 A. No. Gas utility delivery revenues (revenues less gas costs) are subject to fluctuation
6 for many reasons as previously listed, including sales volume variation due to
7 weather, replacement of inefficient older appliances, improved building codes,
8 variation due to conservation and price elasticity effects as well as growth in
9 revenue from adding new customers. The VBA proposal would adjust rates to
10 eliminate gas usage and revenue fluctuations due to weather, replacement of
11 appliances, price elasticity or conservation effects, effectively guaranteeing
12 collection by the utility of the gas margin revenue per customer that was used to set
13 rates. At the same time, the Companies would be allowed to collect and retain for
14 shareholders (not track through rates) any increase in margin revenues associated
15 with adding new customers. The combined effect of rate tracking for anticipated
16 declines in usage per customer, while not tracking favorable revenue impacts from
17 adding customers or other variables, will assure the utilities and their shareholders
18 of stable and increasing future revenue levels while shifting to customers all risks
19 associated with usage per customer declines due to weather and conservation (or
20 any other cause). Customers would pay higher rates due to mild weather or as a
21 result of their collective success in conserving energy, while paying lower rates
22 only when sales growth due to severe winter weather is normalized through the
23 VBA. It is reasonable to expect that implementation of Rider VBA will produce

1 lower annual customer bills only after unusually high usage is experienced due to
2 extreme winter weather. In most years, customers will see increased bills under
3 Rider VBA.

4 **Q. Does traditional ratemaking involve the measurement of overall gas delivery**
5 **volumes, instead of changing rates for only the declining usage “per customer”**
6 **that Mr. Feingold has chosen to focus upon?**

7 A. Yes. This holistic test year approach under traditional regulation is critically
8 important to the establishment of just and reasonable utility rates because it
9 accounts for all elements of the revenue requirement, including the number of
10 customers being served in the test year, their usage levels, and all of the investment
11 and expenses incurred to provide gas delivery services to such customers within the
12 test year. The reasonableness of resulting utility rates is heavily dependent upon a
13 balanced review of all ratemaking elements at a common point in time. Departures
14 from the traditionally balanced test year approach should be implemented only
15 when compelling facts justify upsetting this balance by establishing special cost
16 trackers or accounting deferrals subject to strictly applied regulatory criteria.

17
18 **VII. RIDER ICR – PLANT INVESTMENT TRACKING**
19

20 **Q. At page 3 of his testimony, Mr. Schott proposes a new “Rider ICR” designed to**
21 **“give rate effect to Peoples Gas’ proposal to accelerate the replacement of**
22 **CI/DI mains.” Are predictions of larger future capital investments a**
23 **reasonable basis to change regulatory treatment for such rate base**
24 **investments?**

1 A. No. Capital investment levels by gas distribution utilities tend to vary from year to
2 year and can best be addressed through traditional test year ratemaking procedures.
3 Piecemeal rate rider increases for future increased utility plant investment, in
4 isolation, may contribute to excessive overall rate and revenue levels because other
5 revenue requirement determinants such as labor costs, non-labor expenses, changes
6 in the cost of capital and future revenue margin trends may also significantly impact
7 future achieved returns. PGL has not explained why the productivity gains it has
8 achieved historically, which have allowed it to continuously invest in new utility
9 plant while also earning reasonable returns and avoiding a rate case for more than
10 10 years, will suddenly terminate in the future, such that new piecemeal rate
11 tracking tariffs like Rider ICR are now needed to increase rates between rate cases
12 for any increased capital investments.

13 **Q. Should PGL's proposed new Rider ICR be approved by the Commission?**

14 A. No. This rate rider should be rejected for several reasons, as more fully explained
15 in this section of my testimony, including:

- 16 • Rider ICR represents improper piecemeal regulation for an isolated element of
17 the revenue requirement, addressing plant investment costs that are more
18 properly captured using traditional test year regulation.
- 19 • Rider ICR fails the generally accepted tests for rate tracking tariff riders,
20 because it is not proposed to respond to large, volatile cost changes that are
21 beyond the control of management.
- 22 • Rider ICR fails to account for productivity gains, including those that may
23 arise from accelerated replacement of older cast iron and ductile iron mains.

- 1 • Rider ICR would blunt regulatory lag incentives that should remain in place
2 under traditional regulation to retain focused management attention upon cost-
3 effective investment decisions.
- 4 • Rider ICR is improperly structured because it is not symmetrical, it fails to
5 properly account for growth in depreciation and deferred tax reserves that
6 reduce future rate base costs and it is not limited to only the capital projects
7 directly related to the “Accelerated Program” discussed by Mr. Schott.
- 8 • Rider ICR would improperly increase rates for investments made between rate
9 cases without any Commission review of the prudence of those investment
10 decisions, in apparent violation of both the Illinois Public Utilities Act and
11 longstanding Illinois ratemaking practice and theory that permits recovery in
12 rates for used and useful, prudent utility investment.

13 **Q. How is growth in utility plant investment normally addressed in the regulation**
14 **of gas distribution utilities?**

15 A. New investment in utility plant contributes to the rate base balances that are allowed
16 a return in rate cases. New plant balances are also subject to the accrual of
17 depreciation expense that is recognized for ratemaking purposes. Test year
18 accounting captures the cumulative impact of plant investment additions, plant
19 retirements, accumulated depreciation accruals and accumulated deferred tax
20 balances that are impacted by utility management capital spending. It is significant
21 that such test year accounting maintains the critically important matching of all
22 elements of rate base, operating revenues, expenses and the cost of capital, as
23 previously explained in my testimony.

1 **Q. Has PGL been successful historically in offsetting the costs of newly added**
2 **plant investment as well as inflationary increases in operating expense levels by**
3 **employing new technologies and improving its business practices?**

4 A. According to the Companies, yes. In his Direct Testimony, Mr. Borgard explains
5 that the Company has taken several significant steps to control costs and has made
6 numerous improvements in its operations to create efficiencies, including various
7 new technologies that “allow Peoples Gas to operate and maintain its system with
8 fewer employees than were required in 1995.”³⁸ In fact, these productivity gains
9 have enabled PGL to reduce its number of employees from 2,940 to only 1,564 over
10 the past 11 years, a 47 percent reduction in headcounts. I have attached a copy of
11 PGL’s response to Data Request AG 5.23 that summarizes these employment trends
12 as GCI Exhibit No. MLB-1.4.

13 **Q. Have the productivity improvements and reductions in employee levels helped**
14 **the Companies mitigate the effects of inflation and increasing capital**
15 **investments?**

16 A. Yes. According to Mr. Borgard, “In the 1995 Rate Order, Peoples Gas was allowed
17 to recover \$213 million of operating expenses, excluding bad debt expense...In this
18 rate filing, however, we are requesting recovery of \$215 million for operating
19 expenses, excluding bad debt expense”, indicating how productivity gains have
20 historically offset inflationary pressures upon PGL operating expenses.³⁹

21 **Q. With regard to such productivity measures, would it be reasonable for the**
22 **Commission to assume that no future opportunities remain for PGL or NSG to**

³⁸ Peoples Gas Ex. LTB-1.0, page 13.

1 **continue to improve its operations and to continue the deployment of**
2 **productivity-enhancing new technologies?**

3 A. No. According to the Companies' responses to Data Request No. AG 3.14,
4 management is "...constantly in the process of identifying and implementing
5 technological innovations, evaluating and implementing efficiency measures and
6 investigating and implementing best practices." A complete copy of this response
7 is set forth within GCI Exhibit No. MLB-1.5. Moreover, in light of the companies'
8 recent merger with WPS Resources Corporation, the Companies have an incentive
9 to create and achieve synergies in excess of the amounts incorporated as "known
10 and measurable changes" in the operating expense and income statements submitted
11 in this consolidated docket. Any additional synergies achieved beyond the
12 operating expense adjustments of \$11, 445,400 for Peoples Gas and \$1,633,000 for
13 North Shore will inure to shareholders.⁴⁰

14 **Q. Has the Company made any showing that it may experience attrition in the**
15 **future because of higher expected capital expenditures or for any other**
16 **reason?**

17 A. No. When asked if the Companies (PGL and North Shore) have prepared any
18 "projections of the future financial performance of each Company in years
19 subsequent to the test year, assuming base rate recovery of energy efficiency and
20 uncollectible expenses and no rate tracking for infrastructure plant additions or
21 changes in gas sales volumes/margins" or financial projections "to evaluate the
22 financial impact of any or all of the proposed Riders EEP, UBA, VBA or ICR", the

³⁹ Id, page 12.

1 Companies responded, "There are none." I have attached a copy of this response to
2 Data Request AG 4.05 as GCI Exhibit No. MLB-1.6.

3 **Q. Are the revenue requirement impacts that arise from capital expenditures for**
4 **utility plant large, volatile and beyond the control of management, in relation**
5 **to overall revenue requirement or operating income?**

6 A. No. Capital expenditures translate into revenue requirements at a rate of about 15
7 cents per rate base includable dollar. In its response to Data Request No. AG-4.15,
8 PGL provided illustrative calculations of the Rider ICR calculations that would be
9 submitted in March 2009 assuming Plant Investment Increment expenditures above
10 historical baseline levels of \$32.8 million. At this assumed spending level, the
11 Rider ICR incremental annual revenues would be \$4.9 million, which represents
12 less than one percent of annual PGL non-gas margin revenues at proposed rate
13 levels and only three percent of annual pretax operating income at proposed rate
14 levels.⁴¹ Notably, this revenue requirement impact occurs at about 15 percent of
15 incremental capital spending (\$4.9 million of revenue requirement on \$32.8 million
16 of incremental spending), so PGL would need to vastly expand its incremental
17 capital spending to experience the large or potentially volatile revenue requirement
18 impacts normally required for special rate rider piecemeal rate tracking. I have
19 included a copy of the PGL response to Data Request No. AG-4.15 as GCI Exhibit
20 No. MLB-1.7.

⁴⁰ Ratemaking Adjustment No. 20 for PGL and for NSG appears at Section 285.3015 Schedule C-
2.20 for each utility and is required to reflect Condition No. 13 of ICC Docket Order #06-0540.
⁴¹ PGL Schedule C-1 reflects gross margin income of \$525 million at proposed rates (\$1,609 million
of Operating Revenues, less \$1,084 million Cost of Gas). Pretax Operating Income at proposed
rates consist of after tax "Jurisdictional Operating Income" of \$108 million, plus "Income Taxes"
totaling \$50 million at lines 19-22).

1 **Q. Are PGL capital expenditure levels beyond the control of management, such**
2 **that rate tracking increases and the removal of regulatory lag incentives would**
3 **be reasonable?**

4 A. I certainly hope and trust that PGL management is in control of capital expenditure
5 levels. Significant capital expenditures are continuously required by utilities to
6 replace, extend and modernize gas distribution facilities, and management should
7 be actively involved in facilities planning and design, construction workforce
8 management, materials procurement, contractor bidding and administration and
9 other elements of capital expenditure optimization. At page 20 of his Direct
10 Testimony, Mr. Borgard acknowledges this responsibility in stating, “Prospectively,
11 Peoples Gas will have to continue its cost control activities and continue to push for
12 even more efficiencies to maintain operating and capital costs at a reasonable level
13 into the future so that the need for rate relief will be mitigated.” However, with
14 reference to Mr. Schott’s Rider ICR proposal, Mr. Borgard continues at page 20
15 with the statement, “Also, Peoples Gas is interested in accelerating upgrades of its
16 system if it can receive timely recovery of this investment.”

17 **Q. Would Rider ICR, if approved, reduce the normal regulatory lag incentive that**
18 **a utility faces between rate cases, which serves to encourage careful**
19 **management of capital expenditures?**

20 A. Yes. Rider ICR would provide expedited piecemeal rate increases for incremental
21 capital investment between rate case test years, which would remove the normal
22 regulatory lag efficiency incentives. This is recognized by Mr. Schott in his Direct
23 Testimony that, “Absent Rider ICR, if Peoples Gas were provided with

1 opportunities to accelerate its Existing Replacement Program, the additional costs
2 of replacement would only be recoverable in base rates after the completion of
3 Peoples Gas' next rate case. Even then, return of and on capital between rates cases
4 [sic] would be forgone.”⁴²

5 **Q. Does traditional regulation preclude a utility from taking advantage of cost**
6 **effective opportunities to accelerate or delay capital spending?**

7 A. No. Within the constraints of safety and service quality, management faces a
8 balanced incentive and a range of options under traditional regulation to optimize
9 the resources used in operations, including materials, labor, contract services and
10 capital investment, because all of these resources are subject to the same regulatory
11 treatment with actual costs periodically measured for ratemaking within a balanced
12 test year review process. When making decisions about investing in new plant,
13 management should seek cost effective approaches that meet the requirements of
14 safe and adequate service, while recognizing business opportunities to target such
15 investment to limit excessive plant maintenance expenses and reduce lost and
16 unaccounted for gas (“LUFG”). If accelerating investment levels is an
17 economically justifiable decision, there is no restriction under traditional regulation
18 to preclude such acceleration. One of the problems with proposed Rider ICR is that
19 it removes this balanced incentive by granting expedited piecemeal rate increases
20 for broadly defined incremental plant investments, thereby excusing management
21 from the obligation to carefully manage and optimize capital expenditure levels.

⁴² Peoples Gas Ex. JFS-1.0, page 4.

1 **Q. Is it reasonable to expect that accelerated spending on replacement of mains**
2 **and service lines may create savings for PGL in operations and maintenance**
3 **expenses?**

4 A. Yes. Many types of operations and maintenance expenses are influenced by the age
5 and condition of utility plant. For example, service calls for gas leaks and gas leak
6 repair expenses are impacted by the condition of mains and service lines and the
7 systematic replacement of problem areas in the gas distribution system can produce
8 significant improvement (i.e., reductions) in these costs. Automation opportunities
9 also exist through modernization of distribution facilities, with examples such as
10 automated meter reading, that create staffing and O&M expense reduction
11 opportunities through new capital investments. Therefore, capital investments in
12 gas distribution plant should not be subject to single issue rate tracking unless all of
13 the corresponding operational impacts created by such investments are also
14 recognized within the tracker.

15 In his Direct Testimony, PGL witness Mr. Doerk describes how Peoples
16 Gas uses a “Main Rating Index” to prioritize gas main segments for replacement,
17 using the maintenance history and leak incidence of the main segment as well as
18 other criteria to establish an MRI rating.⁴³ Mr. Doerk notes that “leak repair data
19 compiled over the last ten years validate the effectiveness of the cast iron main
20 replacement program” and that “eliminating low pressure regulating stations
21 reduces ongoing maintenance cost and improves reliability.”⁴⁴ In responding to
22 Data Request CUB-CITY 1.07, the Companies confirmed that “[t]he costs of

⁴³ Peoples Gas Ex. ED-1.0, pages 16-17.

1 maintenance and repair are implicitly considered in making decisions as to the
2 appropriate time to replace distribution facilities.”

3 **Q. Does the existing PGL Gas Main Replacement Program reduce gas leaks and**
4 **O&M Costs?**

5 A. Yes. I have attached as GCI Exhibit MLB-1.9 a presentation prepared by Peoples
6 titled “PGL Gas Main Replacement Program” that was dated August 14, 2006 and
7 provided in response to Data Request No. AG-8.02. According to this document,
8 the existing program has reduced gas leaks (see page NSPGL 1810) and has
9 reduced future O&M costs through “Avoided Future Maintenance Cost for CI/DI,
10 Reduction in Inside Safety Inspections and Repair of Pending Leaks” and has
11 produced savings through “Reduction in Future Bad Debt Losses” (see page
12 NSPGL 1821).

13 **Q. Has PGL proposed that the new Rider ICR account for any savings in**
14 **operating expenses that may result from accelerating the cast iron main**
15 **replacement program?**

16 A. No. Proposed Rider ICR has no component to account for any O&M expense
17 savings. In contrast, if return on and of accelerated gas plant investment were not
18 provided preferential rate tracking treatment through Rider ICR, but were instead
19 handled through traditional test year regulation, all changes associated with such
20 investment would be captured in determining the revenue requirement for the test
21 year.

⁴⁴ Id, lines 364 and 389.

1 **Q. Would it be possible to expand Rider ICR to correct for the matching problem**
2 **associated with ignoring operational benefits that may be created by**
3 **accelerated plant investment?**

4 A. As a practical matter, it would likely be impossible to design a comprehensive
5 tracking mechanism to capture all financial impacts arising from new capital
6 investment because of the capital intensity of the utility business and the complex
7 ways in which changes in utility plant assets impact business operations.

8 **Q. At page 4 of his Direct Testimony, Mr. Schott states, “Rider ICR would give**
9 **Peoples Gas greater flexibility in its ongoing activity involving the replacement**
10 **of CI/DI mains. The Rider would allow Peoples Gas to replace larger amounts**
11 **of CI/DI mains on its system in a considerably shorter time frame than the 40**
12 **to 45 year time frame presently in place.” Is the new Rider ICR tariff limited**
13 **to only incremental spending to accelerate replacement of CI and DI mains?**

14 A. No. Proposed Rider ICR would increase customer rates to provide a return on and
15 depreciation on all “Plant Investment Increment” amounts above historical average
16 investment levels, including all amounts invested in the following PGL Accounts:

17 Account 376 - Mains Account 380 - Services Account 381- Meters
18 Account 382 - Meter Installations Account 383 – House Regulators

19
20 By defining eligible Plant Investment Increment to include all spending in these
21 accounts above historical levels, *regardless of any relationship to the CI/DI*
22 *replacement program*, Rider ICR would produce piecemeal rate increases for new
23 capital investment that goes far beyond the CI/DI main replacement program,

1 including new or replacement mains, services, meters and regulators involving any
2 materials whatsoever. In its response to Staff Data Request No. DLH-1.05, PGL
3 confirmed that its proposed Rider ICR “....does not require the separate
4 identification of the cost of the Accelerated Replacement Program” and in response
5 to Data Request No. AG 7.02 PGL admitted that “Rider ICR would apply more
6 broadly to all investments made in the accounts above.”

7 **Q. In the event PGL capital expenditures in these accounts declines in the future,**
8 **relative to the historical average spending levels specified in the tariff, would**
9 **Rider ICR produce rate reductions for the benefit of customers?**

10 A. No. The structure of the proposed tariff is not symmetrical, such that Rider ICR
11 would not operate to provide credits whenever future capital expenditures in a
12 particular year were lower than average historical spending.⁴⁵ While it is unlikely
13 that future capital spending will decline, because of the requirement in the
14 Commission’s February 7, 2007 order in Docket 06-0540 requiring PGL to
15 maintain its capital spending at or above historical spending levels, the fact that
16 Rider ICR passes along only charges (not savings) to customers demonstrates that it
17 is designed to be beneficial only to the Company’s shareholders.

18 **Q. Has any independent outside consultant study been performed to evaluate the**
19 **adequacy of the Existing CI/DI Main Replacement Program?**

⁴⁵ PGL response to Data Request No. AG 7.07.

1 A. Yes. Such a study was required as a condition of merger approval and was
2 performed by Kiefner & Associates, as described in the testimony of Mr. Schott.⁴⁶

3 At page 1, the Executive Summary of the Kiefner & Associates report states:

4 This report presents the results of a review and assessment of Peoples Gas
5 Light & Coke Company's (PGL) Cast Iron (CI) and Ductile Iron (DI)
6 Replacement Program. The review and assessment suggest that the CI and
7 DI main replacement program currently being carried out by PGL is
8 working effectively in that the pipe is being replaced at a reasonable
9 average rate and the numbers of breaks and cracks are declining.

10

11 Noting the impacts upon operating expenses that result from the CI/DI replacement

12 program, the Kiefner & Associates report states at page 11:

13 PGL implements a "Bang for the Buck" tool that incorporates spatial data
14 (GIS) with their main frame database (GMOS). This is a useful tool in
15 selecting pipe for replacement by combining all segment attribute
16 information, including the MRI number, with things such as areas with a
17 high maintenance cost, or areas that reduce the need for inside safety
18 inspections. The tool yields results by looking at operations and
19 maintenance costs and comparing those costs to the costs of replacement.
20 The ratio of these costs can be used to compare alternative projects. This
21 approach maximizes the benefits of selecting a particular segment for
22 replacement from both a safety and financial standpoint.

23

24 These documents reveal the known interrelationships that exist between gas main

25 investment levels and operational costs, indicating how Rider ICR would

26 improperly increase prices between rate cases to allow piecemeal recovery of

27 accelerated investment costs, while ignoring any operational benefits arising from

28 such accelerated investment. In fact, approval of the proposed Rider may bias the

29 Company's application of its own "tool" because of the more favorable regulatory

30 treatment that would be given the investment cost relative to the associated

⁴⁶ See paragraph No. 23 of Peoples Gas Ex. LTB-1.6 at page 5 and Peoples Gas Ex. JFS-1.0 page 5.

operational impacts, potentially encouraging uneconomically excessive future plant investment acceleration.

Q. Does PGL have a reasonable opportunity to continue to select main replacement projects with consideration of safety and financial issues under traditional test year regulation?

A. Yes. Mr. Schott and the Kiefner & Associates work confirms that the Existing Main Replacement Program, which has been functioning for many years under traditional regulation, has been conducted in a prudent and reasonable manner and represents a measured and safe approach to CI/DI replacement.⁴⁷ If PGL decides in the future to prioritize specific projects under this Program and to accelerate or defer individual activities, either to achieve safety or financial benefits, all the costs and all of the benefits of such activities would be recognized each time a new rate case test year is analyzed. This balanced review within a test year rate case ensures that any benefits arising from CI/DI replacement or any unrelated productivity gains realized elsewhere in the business are fully considered whenever increased plant investment costs are considered for inclusion in rate base. Moreover, I’m advised by counsel that if the Company can specifically quantify any planned expenditures associated with the accelerated program that “are reasonably certain to occur”⁴⁸ within 12 months after the filing dates of the tariffs, the Company is free to propose pro forma adjustments to the test year, as permitted by Commission rules.

⁴⁷ Peoples Gas Ex. JFS-1.0, page 5.

⁴⁸ See 83 Ill. Admin. Code Part 287.40 (Pro Forma Adjustments to Historical Test Year)

1 **Q. Has the Company concluded that continued future capital investment in the**
2 **cast iron main replacement program at recent historical levels will not allow it**
3 **to maintain a safe and reliable system?**

4 A. No.⁴⁹

5 **Q. Are you recommending that Peoples abandon its plan to expedite its cast iron**
6 **and ductile iron main replacement program?**

7 A. No. My testimony does not challenge or comment upon the need for the
8 accelerated program. The issue is that Rider ICR, as proposed by PGL, would
9 produce piecemeal rate increases for new capital investment that go far beyond the
10 CI/DI main replacement program, as noted above.

11 **Q. Are there other mechanical flaws in the structure of Rider ICR, beyond the**
12 **facts that the Rider does not capture any O&M expense savings, is not limited**
13 **to only accelerated CI/DI replacement and is not symmetrical?**

14 A. Yes. The rider fails to account for additional deferred income taxes arising from
15 incremental plant investment. A review of proposed Rider ICR, as set forth in
16 Peoples Gas Ex. VG-1.1 at pages 142 through 144 reveals computation of a “Rate
17 Base RB” value that recognizes “Plant Incremental Investment PII”, less
18 “Accumulated Reserve for Depreciation AD”, but with no further subtraction for
19 accumulated deferred income taxes which would also arise from incremental capital
20 spending.

21 There is also a problem with the narrowly defined “Accumulated Reserve
22 for Depreciation AD” term that is limited to depreciation accruals only upon the

⁴⁹ PGL response to Data Request No. AG 8.01.

1 Plant Investment Increment dollars. In reality, PGL continues to collect
2 depreciation and build its Accumulated Reserve for Depreciation based upon
3 application of depreciation accrual rates to all plant investment, not just incremental
4 investment. In fact, depreciation on embedded prior year capital investment
5 produces considerable cash flow for PGL that is available for reinvestment in
6 incremental new plant.

7 Another problem with proposed Rider ICR is the complete failure to
8 account for plant retirement activity. Whenever plant replacement activity occurs,
9 there should be a plant asset addition as well as corresponding retirements of
10 existing plant. While retirement entries do not change rate base, because of the
11 simultaneous recording of a reduction to Plant in Service and a reduction to
12 Accumulated Reserve for Depreciation, there should be a direct reduction in
13 depreciation expense accruals associated with removal of the retired plant.

14 **Q. Can the input values and computations involved in administering the**
15 **Company's proposed Rider ICR plant investment tracking tariff be readily**
16 **audited and verified through expedited regulatory reviews?**

17 A. No. The proposed Rider ICR tariff relies upon several input values that should
18 become "fixed" in this rate case, including the historical average plant investment
19 baseline value and the pretax return rate, but the annual capital expenditure amounts
20 in each account that drive all the calculations would need to be verified each year.
21 PGL provided illustrative calculations of the annual Rider ICR filings it proposes in
22 its response to Staff Data Request No. DLH-1.03, which I have attached as GCI
23 Exhibit MLB-1.8. Five pages of calculations are contemplated in total, with the key

1 cost inputs being the “Plant Investment PI” amounts inserted for each year by Gas
2 Plant Account Number. The Company contemplates rapid implementation of Rider
3 ICR rate increases, with a filing in March each year and rate implementation by
4 April 1, which would allow no substantive analysis or audit of the plant costs that
5 would cause such rate increases. Any problems with plant cost classification
6 between accounts, AFUDC accruals contributing to total capitalized costs and
7 validation of construction work completion by year-end would need to be resolved
8 to implement annual rate changes by April 1 of each year.⁵⁰ Proposed Rider ICR
9 raises a fundamental question regarding whether it is necessary for any Staff audit
10 or other regulatory examination to occur before new plant investments can be
11 included within rate base for cost recovery from customers. The primary input
12 values under the proposed Rider ICR would be the “Plant Investment Increment”
13 recorded each year, but this amount is directly impacted by the total amount of
14 capital spending incurred to reach and exceed the average baseline amounts. Thus,
15 every dollar of capital investment in the eligible Plant Accounts could translate into
16 rate adjustments. In the event the Commission or Staff determine that any prudence
17 review or financial audit of recorded plant investments is required prior to
18 increasing rates to recover the incremental new plant investment, considerable
19 administrative costs may be added with implementation of Rider ICR.⁵¹

⁵⁰ Peoples Gas Ex. VG-1.1, pages 142-144 set forth the proposed Rider ICR terms and calculations.
⁵¹ In its response to Staff Data Request No. DLH 1.09, the Company agreed, “... to add a section that will require an annual internal audit of the ICR Rider.” However, the scope of that internal audit would not address the reasonableness or prudence of actual recorded plant investment dollars driving the Rider ICR calculations, but instead would be limited to “determine that the annual filing referred to in our response to DLH 1.08 has been calculated in accordance with the Tariff.”

1 **Q. Does the proposed Rider ICR include any examination of the prudence of**
2 **investments made and recovered in rates?**

3 A. No, it does not. This potentially serious omission in the ratemaking process
4 contradicts the established practice of permitting recovery in rates of only
5 investments determined to be prudently incurred and used and useful by the
6 Commission. Even if the Company agreed to amend its proposed Rider to
7 incorporate a prudence determination, the added complexity and administrative
8 burden associated with such an analysis further supports rejection of this rider
9 proposal.

10 **Q. What is your conclusion and recommendation regarding PGL's proposed Rider**
11 **ICR?**

12 A. I have concluded that Rider ICR is an unreasonable deviation from traditional test
13 year regulation, is destructive of test year matching and will systematically overstate
14 the Company's revenue requirement by failing to reasonably account for all of the
15 changes in costs that are associated with changes in plant investment levels. PGL has
16 failed to show that Rider ICR is needed and that the rider is properly restricted to the
17 stated purpose of accelerating the Company's CI/DI main replacement program.
18 Further, if implemented, Rider ICR would dilute important incentives to management
19 to efficiently manage capital investment activities. I recommend Rider ICR not be
20 approved by the Commission for all the reasons stated herein.

21

22 **VIII. RIDER UBA – UNCOLLECTIBLE EXPENSE TRACKING**

23

1 **Q. Another piecemeal tracking tariff proposed by the Companies is a bad debt**
2 **expense tracker that has been labeled the “Uncollectible Balancing**
3 **Adjustment” or “UBA”. What are the reasons stated by Company witnesses in**
4 **support of this proposed rider?**

5 A. Mr. Borgard states that fluctuations in bad debt expense can be attributed to
6 changes in the price of gas being recovered by the utilities, and that a problem
7 occurs because bad debts are recovered in a fixed amount through base rates,
8 contributing to significant under- or over-recoveries of such costs.⁵² He sponsors
9 Peoples Gas Ex. LTB-1.5 and North Shore Ex. LTB-1.4 to illustrate such
10 fluctuations around the amount of expense last allowed in the Companies’ 1995 rate
11 case. Mr. Feingold asserts that the “greater magnitude and more volatile nature of
12 bad debt experienced by utilities are certainly more challenging and are caused by
13 events that are almost entirely out of the control of the utilities.” He explains
14 certain credit and collection changes and termination of service opportunities that
15 have been employed by the Companies and other utilities, but he concludes that
16 Rider UBA is needed because it will provide “the ability to recover the ongoing
17 level of bad debt expenses related to purchased gas costs that are largely
18 uncontrollable, variable and of an unpredictable nature, particularly in an
19 environment of widely fluctuating gas costs.”⁵³

20 **Q. One of the criteria you mentioned for piecemeal rate tracking in earlier**
21 **testimony is that tracked costs should be substantial enough to have a material**
22 **impact upon revenue requirements and the financial performance of the**

⁵² Peoples Gas Ex. LTB-1.0, page 26, North Shore Ex. LTB-1.0, pages 24-25.

1 **business between rate cases. How large were the historical annual changes in**
2 **bad debt expense that would be subject to tracking under a Rider UBA tariff**
3 **mechanism?**

4 A. With reference to Mr. Borgard's Exhibit LTB-5 for PGL and LTB-4 for NSG, the
5 largest historical year swing in bad debts in total would appear to be in 2001, when
6 such expenses more than doubled from less than \$20 million for PGL in 2000 to
7 nearly \$40 million in 2001, with smaller but still significant percentage increases
8 experienced by North Shore in that year. As with the Rider VBA impacts discussed
9 above, Rider UBA is not obviously consistent with the first evaluative criterion I
10 describe for piecemeal rate tracking -- that the cost changes it tracks be substantial
11 enough to have a material impact upon revenue requirements and the financial
12 performance of the business between rate cases. With regard to PGL, a change in
13 annual expense of \$20 million represents less than four percent of annual margin
14 revenues at proposed rate levels.⁵⁴ In the years other than 2001, the fluctuation in
15 historical bad debt expenses was much smaller than \$20 million.

16 **Q. Have bad debt expenses been volatile in the past, such that rate rider tracking**
17 **is justified to protect the financial integrity of the utility?**

18 A. Some volatility has been experienced in certain prior years, as evidenced by the
19 aforementioned Peoples Gas Ex. LTB-1.5 and North Shore Ex. LTB-1.4,
20 particularly in 2001 when gas commodity prices increased significantly and
21 customers experienced difficulties in paying much higher utility bills. However,
22 since that time, bad debt fluctuations have moderated. Assuming the Commission

⁵³ Peoples Gas Ex. RAF-1.0, pages 37-40 North Shore Ex. RAF-1.0, pages 34-37.

1 incorporates a normal, ongoing level of bad debt expense within the revenue
2 requirement, fluctuations in future bad debt expenses around such newly-allowed
3 levels set in this case should not be large enough to jeopardize the financial
4 integrity of the utility.

5 **Q. Should the fluctuations in experienced uncollectible expenses be considered to**
6 **be beyond the control of management between rate cases, another important**
7 **criterion for tariff rider piecemeal regulation?**

8 A. Not entirely. Management clearly exerts a degree of control over its credit and
9 collection policies, within the constraints of the rule imposed by the Commission
10 regarding such matters. On this point, Ms. Kallas testifies that Peoples Gas has
11 been able to control and reduce the bad debt write-off rate through a number of
12 enhanced credit and collection procedures.⁵⁴ Traditional regulation of bad debt
13 expense preserves a strong regulatory lag incentive for utility management to
14 carefully manage credit risks and collection policies.

15 **Q. Are the calculations associated with proposed Rider UBA administratively**
16 **complex?**

17 A. Yes. Peoples Gas Ex. VG-1.14 and North Shore Ex. VG-1.13 sponsored by Ms.
18 Grace set forth the series of monthly calculations required to administer the
19 proposed new Rider for each utility. While the “Factor UEP” bad debt percentage
20 would be a fixed value established in the rate case order, each month’s Estimated
21 Gas Charge Revenue would be multiplied by this value and then divided by
22 forecasted therms expected to be delivered, as shown on page 2 of Ms. Grace’s

⁵⁴ PGL Schedule C-1, total Operating Revenues at proposed rates of \$1,609 million, less Cost of Gas

1 Exhibits. Because the monthly UBA calculated charge amounts are based upon
2 estimated values, it is necessary to calculate a true-up to actual Gas Charge revenue
3 amounts times the UEP factor, to develop a “Reconciliation Adjustment” for the
4 previous year that is shown at page 3 of Ms. Grace’s Exhibits. An additional
5 provision for interest on over and under-recovered amounts appears at line 6 of the
6 page 3 calculations of the annual reconciliation. Then, because the annual
7 reconciliation amounts are also subject to over or under-recovery, a further true-up
8 is required, as shown in the page 4 calculations of the “Determination of
9 Reconciliation Adjustment – RA” of Ms. Grace’s Exhibits.

10 **Q. Aside from the monthly rate calculations and reconciliations for PGL and for**
11 **North Shore, would it be reasonable to expect other jurisdictional utilities to**
12 **seek similar piecemeal tariff riders if this proposal is approved by the**
13 **Commission?**

14 A. Yes. Any opportunity to shift cost responsibility and operational risks associated
15 with bad debt expenses to customers, if approved for these Companies, would likely
16 elicit similar proposals for such piecemeal ratemaking by other gas utilities, adding
17 additional tariff and administrative complexity and costs for the utilities and the
18 Commission Staff.

19 **Q. Are you aware of any utility for which tariff tracking for the commodity cost**
20 **portion of bad debts was approved by a state regulator, only to have that**
21 **decision reversed upon reconsideration?**

⁵⁵ of \$1,084 million yields proposed margin revenues of \$525 million.
Peoples Gas Ex. LK-1.0, page 17,

1 A. Yes. In Docket No. 30010-86-GT-06, the Public Service Commission of Wyoming
2 issued a Memorandum Opinion, Findings and Order dated April 4, 2007 that
3 reversed a previous decision that had allowed Questar Gas Company to include bad
4 debt expenses in that utility's purchased gas commodity balancing account
5 ("CBA"). In that decision, the Wyoming Commission wrote:

6 49, In Docket No. 30010-GP-02-65, the Commission granted
7 Questar authority to include commodity-related bad debt costs in
8 its CBA. Approval was granted pursuant to the Commission's
9 previous Rule Sections 249 & 250, which at that time, contained
10 language that was broader and less defined relative to the types of
11 costs permitted to be included in pass-on applications and CBA
12 mechanisms. OCA takes issue with the company's inclusion and
13 recovery of bad debt expense in the commodity balancing account
14 portion of its purchased gas adjustment filing and recommends the
15 Company be directed to exclude commodity-related bad debt
16 expense from its gas cost adjustment mechanism on a prospective
17 basis, and recalculate its commodity balancing account back to
18 what is [sic] was in 2002 in Docket No. 30010-GP-02-65 (the date
19 the Company commenced inclusion of commodity-related bad debt
20 expense in its CBA filings) to reflect the removal of the bad debt
21 expense adjustment.

22
23 50. A Commission majority finds OCA has supported its
24 position, as reflected in Ms. Parrish's testimony, against the
25 inclusion and recovery of bad debt expense through the CBA
26 mechanism. (Tr.,pp.146-146, 169-170, 184-193, 227-232; OCA
27 Exhibit 1, pp. 8-14) OCA argues bad debt expense should be
28 considered and recovered as an operating expense within the
29 context of a general rate case if supported by the utility. A
30 Commission majority finds the practice of including and
31 automatically recovering all, or a portion, of bad debt expense
32 through the CBA mechanism shifts more of the risk of bad debt
33 expense recovery from shareholders to customers and may provide
34 a disincentive for a utility to actively enforce its bad debt
35 collection practices. A Commission majority finds the
36 examination and provision for recovery of bad debt expense is
37 more appropriately addressed within the context of the general rate
38 case process, as has been the historical practice.⁵⁶
39

⁵⁶ The Wyoming Order can be found at: <http://psc.state.wy.us/htdocs/orders/30010-86-16807.htm>

1

2 **Q. What is your recommendation with respect to the proposed Rider UBA for**
3 **Peoples Gas and North Shore?**

4 A. I recommend that this Rider proposal be rejected and bad debt expense continue to
5 be reviewed and addressed in general rate cases, as has been the historical practice
6 in Illinois, for all the reasons stated herein.

7

8 **IX. RIDER EEP – CONSERVATION FUNDING RIDER**
9

10 **Q. The final new piecemeal tracking tariff being proposed by the Companies is an**
11 **Energy Efficiency Program funding tracker that has been labeled the “Rider**
12 **EEP”. What are the reasons stated by Company witnesses in support of this**
13 **proposal?**

14 A. According to Company witness Mr. Feingold, “proposed Rider EEP will provide
15 for funding for the costs of energy conservation and efficiency programs for its
16 customers commensurate with the implementation of each program through
17 qualified, independent third-part administrator(s)...Rider EEP ensures that the
18 defined level of funding is made available on an ongoing basis to the chosen service
19 providers and that the utility’s applicable customers will be charged only for the
20 program costs actually incurred as the types and mix of implemented programs
21 changes over time.”⁵⁷

⁵⁷ Peoples Gas Ex. RAF-1.0, page 42, North Shore Ex. RAF-1.0, page 39.

1 **Q. Does either the size or anticipated volatility of conservation funding expense**
2 **justify a special tariff Rider for this element of the Companies' revenue**
3 **requirement?**

4 A. No. The Companies' conservation funding obligation that would be addressed by
5 proposed Rider EEP is a fixed \$7.5 million annual amount across both utilities, an
6 amount that is not expected to change in the foreseeable future. Such a fixed
7 expense can and should be included in the basic revenue requirement in these
8 consolidated dockets to "ensure that the defined level of funding is made available
9 on an ongoing basis" as suggested by Mr. Feingold.

10 **Q. In describing how the proposed tariff Rider EEP would be administered,**
11 **Company witness Ms. Grace notes: "As budget dollars may not be fully**
12 **expended as the program is building awareness in the initial program years,**
13 **the Company proposes to carry over up to 75%, 50% and 25% of budget**
14 **dollars into the second, third and fourth program years."**⁵⁸ **Does this**
15 **carryover proposal justify approval of Rider EEP?**

16 A. No. Differences in actual disbursements for conservation programs, relative to the
17 \$7.5 million of committed funding need not be addressed with a tariff rider. If the
18 Commission is concerned with differences between recoveries from customers and
19 actual expenditures by the utilities, a deferral accounting mechanism should be
20 employed to track and reconcile differences between recovery (through base rates)
21 and disbursements made by each utility for conservation programs. Then, in future
22 rate case proceedings, any unspent balance in the deferral account could be

⁵⁸ PGL Ex. VG-1.0, p. 40, 41; NS Ex. VG-1.0, p. 36.

1 evaluated and recognized in the establishment of a revised ongoing recovery level
2 within new base rates. For example, if base rate recoveries total \$22.5 million after
3 three years, but only \$17.5 million has been disbursed, the Commission might
4 consider either directing larger annual disbursements for a period of time after year
5 three or instead reduce the recovery rate embedded in a next rate case occurring at
6 that time. If a full accounting for the economic value of base rate recovered
7 conservation funding was desired, interest could be applied monthly to the
8 cumulative over- or under-recovered balance in the regulatory asset or liability
9 deferral account.

10 **Q. Would base rate recovery of energy efficiency funding, along with approval of**
11 **deferral accounting to reconcile differences between base rate recoveries and**
12 **expenditures, ensure full recovery of all conservation amounts actually**
13 **disbursed by the Companies?**

14 A. Yes. In addition, under this simpler approach, there would be no need for arbitrary
15 limitations upon unspent amounts that are eligible for “carryover” as described in
16 Ms. Grace’s testimony. The full value of all committed funding for conservation
17 could be made available under the regulatory asset deferral accounting alternative I
18 am proposing.

19 **Q. Are there administrative benefits associated with base rate recovery with**
20 **deferral accounting that you describe, relative to a separate piecemeal rate**
21 **tracker?**

22 A. Yes. There would obviously be administrative cost savings to the utilities and the
23 Commission Staff by avoiding the creation of an additional tariff Rider with

1 periodic filings to review and reconciliation adjustments to calculate and apply. In
2 response to ICC Staff Data Request No. DLH-2.16, the Companies "...agree[d] to
3 add a section that will require an annual internal audit of the annual statement of
4 activity and annual report of the Reconciliation Adjustment of the EEP for each
5 Company." The time and expense of such annual audits could be avoided without
6 Rider EEP, with program activities and costs instead addressed in periodic general
7 rates cases where all parties with an interest in such matters can readily participate.

8 **Q. In the event legislation creates new or different conservation funding**
9 **obligations for the Companies, is Rider EEP needed to implement such**
10 **changes?**

11 A. No. If funding changes are not large in relation to the existing \$7.5 million
12 commitment, the deferral accounting I have proposed as an alternative to Rider EEP
13 should be sufficient to track and reconcile differences in conservation funding that
14 may occur in the future. If radical revisions to the funding level are implemented,
15 the interest provision within deferral accounting could be relied upon to make the
16 Company or ratepayers "whole" for any large differences between base rate
17 recovery and spending levels until recovery levels are revised in a next rate case.

18 **Q. Please summarize your specific recommendations regarding the Companies'**
19 **proposed energy efficiency program Rider EEP.**

20 A. For all of the reasons explained in my testimony, I recommend the Commission
21 reject the proposed EEP Rider and provide for base rate recovery of the fixed
22 amount of funding obligation for energy efficiency programs, as set forth in the

1 Conditions of Approval that were implemented by Commission Order in Docket

2 No. 06-0540.

3 **Q. Does this conclude your testimony at this time?**

4 A. Yes.

Decoupling: Should Ratepayers Be Worried?

Simon ffitch
Public Counsel
Washington State Attorney General's Office
Presentation to NARUC Summer Committee Meetings
San Francisco, California
August 2, 2006

What is the stated objective?

Aligning regulatory incentives with demand-side resources

Removing regulatory disincentives to investment in energy efficiency

- Eliminating the conflict between profitability and energy efficiency

Underlying Premises

Utilities will not invest in energy efficiency without special financial incentives.

It is possible to accurately identify the sales and revenue declines that result from energy efficiency efforts by consumers.

- Those declines are significant to the utility.

Answer (?)

decoupling –to sever the link between
utility sales and revenues

Decoupling Packaging

Decoupling breaks the link between the volume of therm sales and the recovery of fixed costs and would provide for an **increased focus on energy efficiency and conservation.**"

Avista Petition to WUTC for natural gas decoupling mechanism, Docket UG-060518)(emphasis added)

What if you don't get it right?

• Poorly designed decoupling can result in:

- Unnecessary expense for ratepayers
- A mere revenue stabilization mechanism for the utility
- A significant shift of risk from shareholders to ratepayers
- Over-recovery for the utility
- Failure to achieve gains in energy efficiency
- Piecemeal regulation

What if you don't get it right?

"disguised rate increase" problem

A 10 percent general rate increase disguised as "decoupling." Use of 10 year old test year as basis for average use per customer meant customers were not compensated for historic declines and saw nearly 10 percent per year increases even under normal weather with no additional conservation. (Cascade Natural Gas, WUTC Docket No. 051651)(WITHDRAWN)

The "windfall profits" problem

A proposal to lock in fixed cost recovery through a decoupling mechanism when the utility could sell conserved power in the wholesale market for more than retail rates, so that any reduction in retail sales would increase profits, even without a decoupling mechanism. (WUTC v. PacifiCorp, WUTC Docket No. UE-050684)(REJECTED)

Many factors contribute to decline in use per customer

• Price elasticity

• Non-company sponsored conservation

• Federal appliance efficiency standards

- Turnover of housing stock

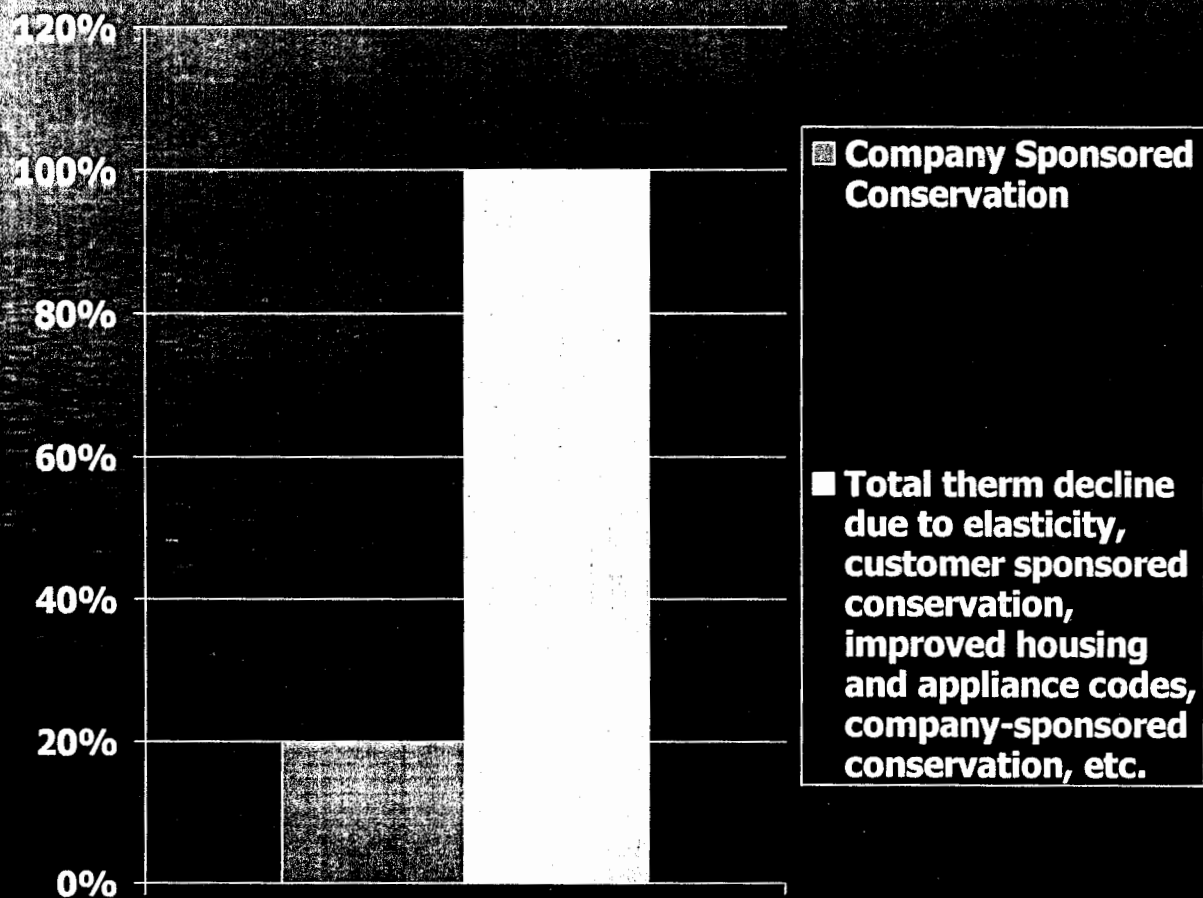
- More efficient building codes

- Economic conditions

- Government sponsored energy efficiency

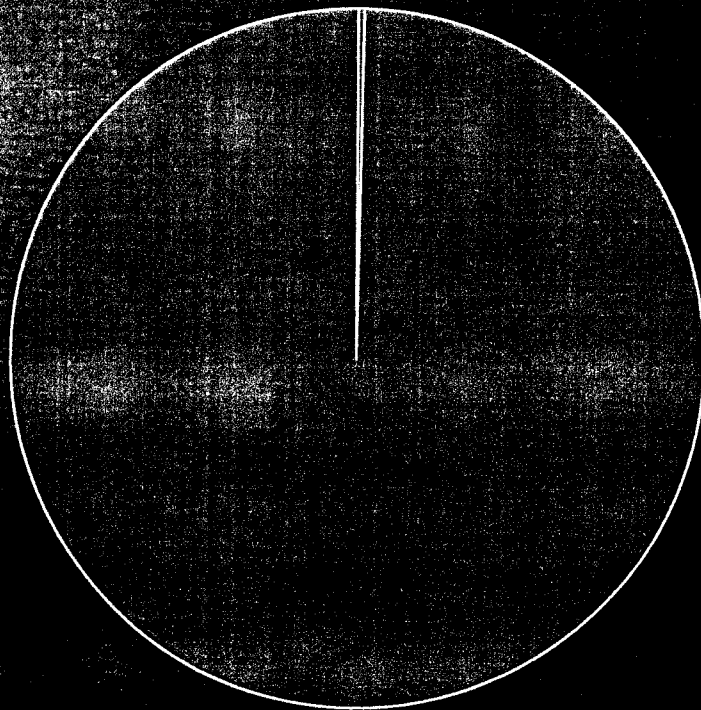
The Scale of the Problem:

Percentages of residential therm decline



Scale of the Problem:

Lost sales from utility conservation programs
compared to total sales



■ Lost Therms = 0.2%
□ Total Sales = 99.8%

Policy Question

What extent do you want to guarantee recovery of revenue lost due to ALL of the factors that cause decline?

- (Not -- are you in favor of energy efficiency?)

What do customers want?

- Affordability (stop the beatings!)
- Stability - Infrequent rate changes
- Bills they can understand
- Balanced, non-piecemeal regulation
- Conservation and energy efficiency

What does decoupling offer?

- More complexity (e.g. weather adjustments, new customer issue)
- More frequent rate changes
- Less stability
- More confusion
- Another "tracker" that changes customer rates without a rate case
- Piecemeal regulation of an isolated, negative industry trend in usage per customer

What is the stated objective again?

Aligning regulatory incentives with demand-side resources

Removing regulatory disincentives to investment in energy efficiency

- Eliminating the conflict between profitability and energy efficiency

Before we throw money at the problem, is there:

• Utility track record of conservation and energy efficiency?

• Experienced and committed utility staff?

• Supporting state and regional infrastructure, institutions (e.g. Northwest Power and Conservation Council, NW Energy Efficiency Alliance, State Energy Office)?

- Third party vendors, evaluators?

- Robust conservation resource analysis as part of integrated resource/least cost planning?

Alternatives to decoupling

• Cost margin recovery mechanism

• Conservation/energy efficiency incentive mechanism

- Third party provider of energy efficiency services

"Twelve Issues" any decoupling proposal must address:

- Scope of risk (conservation, weather or both)
- Scope of fixed costs included
- Customer classes included
- True up accounting detail
- Method of cost recovery
- Design of pilot test period and evaluation method

the "twelve issues" continued...

- Modeling and calculation of rate adjustments
- Impact of new customers on revenue recovery
- Impact on low-income customers
- Identification of incremental conservation measures to be undertaken
- Development of energy conservation targets.

— WUTC v. PacifiCorp, UE-050684, Order No. 04, April 17, 2006 (rejecting decoupling proposal)

Things tried and discontinued in Washington

1980-1990 2 % Bonus Rate of Return Result: incentive to spend more on conservation programs, regardless of cost-effectiveness

1990-91 ECAC Conservation incentive award based on short-term energy savings

Result: incentive for cream-skimming

- 1991-96 Periodic Rate Adjustment Mechanism (PRAM) with full distribution cost decoupling

Result: Steady upward rate adjustments

Conclusion

What is the goal?

More company-sponsored energy efficiency and conservation?

- If so, is decoupling the most affordable, and effective way to direct ratepayer and company resources?

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,

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:

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Administrative Law Judge:

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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

1 DIRECT TESTIMONY OF
2 DAVID E. DISMUKES, PH.D.
3 ON BEHALF OF THE
4 MICHIGAN ATTORNEY GENERAL
5 CASE NUMBER U-14893

6 **I. INTRODUCTION**

7 **Q. WOULD YOU PLEASE STATE YOUR NAME AND BUSINESS**
8 **ADDRESS?**

9 A. My name is David E. Dismukes. My business address is 6455 Overton
10 Street, Baton Rouge, Louisiana.

11 **Q. WOULD YOU PLEASE STATE YOUR OCCUPATION AND CURRENT**
12 **PLACE OF EMPLOYMENT?**

13 A. I am a Consulting Economist with the Acadian Consulting Group (“ACG”),
14 a research and consulting firm that specializes in the analysis of regulatory,
15 economic, financial, accounting, statistical, and public policy issues associated
16 with regulated and energy industries. ACG is a Louisiana-registered partnership,
17 formed in 1995, and is located in Baton Rouge, Louisiana with additional staff in
18 Los Angeles, California, and Carson City, Nevada.

19 **Q. HAVE YOU PREPARED ANY ATTACHMENTS TO YOUR TESTIMONY**
20 **OUTLINING YOUR QUALIFICATIONS IN ENERGY AND REGULATED**
21 **INDUSTRIES?**

22 A. Yes. Attachment 1 to my testimony provides my academic vita that
23 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 began 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 nor 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

1. *Power System Operations and Planning in a Competitive Market*. (2002). With Fred I. Denny. New York: CRC Press.
2. *Distributed Energy Resources: A Practical Guide for Service*. (2000). With Ritchie Priddy. London: Financial Times Energy.

PUBLICATIONS: PEER REVIEWED ACADEMIC JOURNALS

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3. "Deregulation of Generating Assets and the Disposition of Excess Deferred Federal Income Taxes." (2004). With K.E. Hughes II. *International Energy Law and Taxation Review*. 10 (October): 206-212.
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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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9. "Cogeneration and Electric Power Industry Restructuring" (1999). With Andrew N. Kleit. *Resource and Energy Economics*. 21:153-166.
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11. "Oil Spills, Workplace Safety, and Firm Size: Evidence from the U.S. Gulf of Mexico OCS." (1997). With O. O. Iledare, A. G. Pulsipher, and Dmitry Mesyanzhinov. *Energy Journal* 4: 73-90.
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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.

PUBLICATIONS: PEER REVIEWED PROCEEDINGS

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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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PUBLICATIONS: OTHER SCHOLARLY PROCEEDINGS

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3. "Competitive Bidding in the Electric Power Industry." (2003). *Proceedings of the Association of Energy Engineers*. December 2003.
4. "The Role of ANS Gas on Southcentral Alaskan Development." (2002). With William Nebesky and Dmitry Mesyanzhinov. *Proceedings of the International Association for Energy Economics: Energy Markets in Turmoil: Making Sense of It All*. October.

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29. "Clean Air, Kyoto, and the Boy Who Cried Wolf." (2000). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. December: 529-540.
30. "Energy Conservation Programs and Electric Restructuring: Is There a Conflict?" (2000). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. September: 211-224.
31. "The Post-Restructuring Consolidation of Nuclear-Power Generation in the Electric Power Industry." (2000) With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 49: 751-765.
32. "Issues and Opportunities for Small Scale Electricity Production in the Oil Patch." (2000). With Ritchie D. Priddy. *American Oil and Gas Reporter*. 49: 78-82.
33. "Distributed Energy Resources: The Next Paradigm Shift in the Electric Power Industry." (2000). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 48:593-602.
34. "Coming to a Neighborhood Near You: The Merchant Electric Power Plant." (1999). With K.E. Hughes II. *Oil, Gas, and Energy Quarterly*. 48:433-441.
35. "Slow as Molasses: The Political Economy of Electric Restructuring in the South." (1999). With K.E. Hughes II. *Oil, Gas, and Energy Quarterly*. 48: 163-183.
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.
38. "Electric Utility Mergers and Acquisitions: A Regulator's Guide." (1996). With Kimberly H. Dismukes. *Public Utilities Fortnightly*. January 1.

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1. *The Importance of Energy Production and Infrastructure in Plaquemines Parish*. (2006). Report Prepared on Behalf of Project Rebuild Plaquemines.
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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.
4. *Economic Opportunities for a Limited Industrial Retail Choice Plan in Louisiana*. (2004). With Elizabeth A. Downer and Dmitry V. Mesyanzhinov. Baton Rouge, LA: Louisiana State University Center for Energy Studies.
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*.

(2002) With Robert H. Baumann, Dmitry V. Mesyanzhinov, and Allan G. Pulsipher. Baton Rouge, LA: Louisiana Department of Natural Resources, Office of Mineral Resources.

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.
13. *The Economic Impacts of Merchant Power Plant Development in Mississippi*. (2001). Report Prepared on Behalf of the US Oil and Gas Association, Alabama and Mississippi Division. Houston, TX: Econ One Research, Inc.
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.
16. *Restructuring the Electric Utility Industry: Implications for Louisiana*. (1996). With Allan Pulsipher and Kimberly H. Dismukes. Baton Rouge, LA: Louisiana State University, Center for Energy Studies.

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.
7. *Principal Investigator*. "An Examination on the Development of Liquefied Natural Gas Facilities on the Gulf of Mexico." (2004). With Dmitry V. Mesyanzhinov and Mark J. Kaiser. U.S. Department of the Interior, Minerals Management Service. Total Project Funding \$101,054. Status: Awarded, In Progress.
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.
10. *Principal Investigator*. "Marginal Oil and Gas Properties on State Leases in Louisiana: An Empirical Examination and Policy Mechanisms for Stimulating Additional Production." (2002). With Robert H. Baumann and Dmitry V. Mesyanzhinov. Louisiana Office of Mineral Resources. Total Project Funding: \$72,000. Status: Completed.
11. *Principal Investigator*. "A Collaborative Investigation of Baseline and Scenario Information for Environmental Impact Statements." (2002). With Dmitry V. Mesyanzhinov and Williams O. Olatubi. U.S. Department of Interior, Minerals Management Service. Total Project Funding: \$600,000. Status: Awarded, In Progress, four year project.
12. *Co-Principal Investigator*. "An Analysis of the Economic Impacts of Drilling and Production Activities on State Leases." (2002) With Robert H. Baumann, Allan G. Pulsipher, and Dmitry V. Mesyanzhinov. Louisiana Office of Mineral Resources. Total Project Funding: \$8,000. Status: Completed.
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

Enhancement Program, LSU Office of Research and Development. Total Project Funding: \$19,948. Status: Completed.

17. *Co-Principal Investigator*. "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. U.S. Department of Interior, Minerals Management Service, Grant Number 95-0056. Total Project Funding: \$109,361. Status: Completed.

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/USAAE 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; ratepaying 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

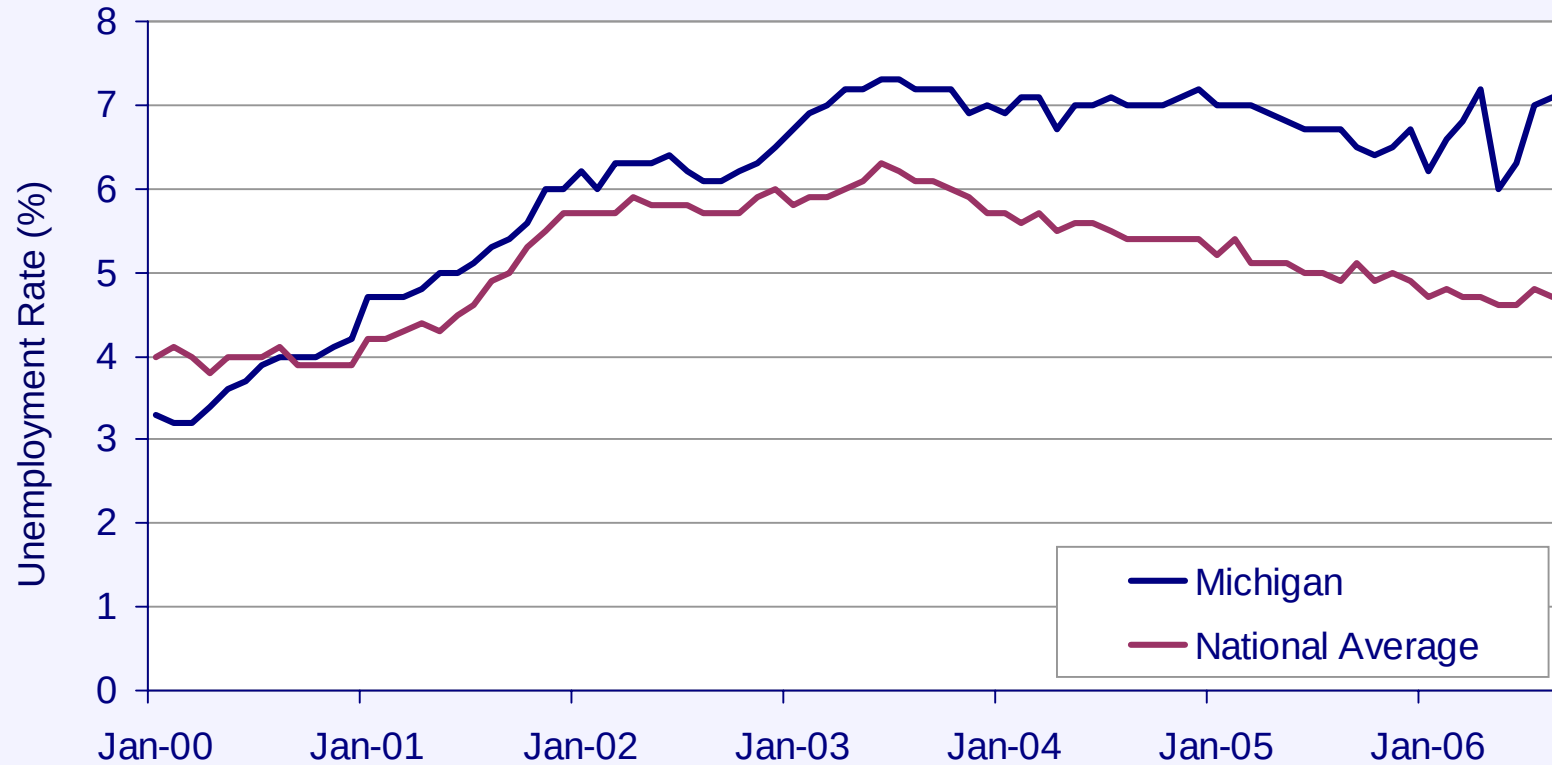
Advisor, Louisiana LNG Buyers/Developers Summit, Office of the Governor/Louisiana Department of Economic Development/Louisiana Department of Natural Resources, and Greater New Orleans, Inc. (2004).

Michigan Unemployment

Case No.: U-14893

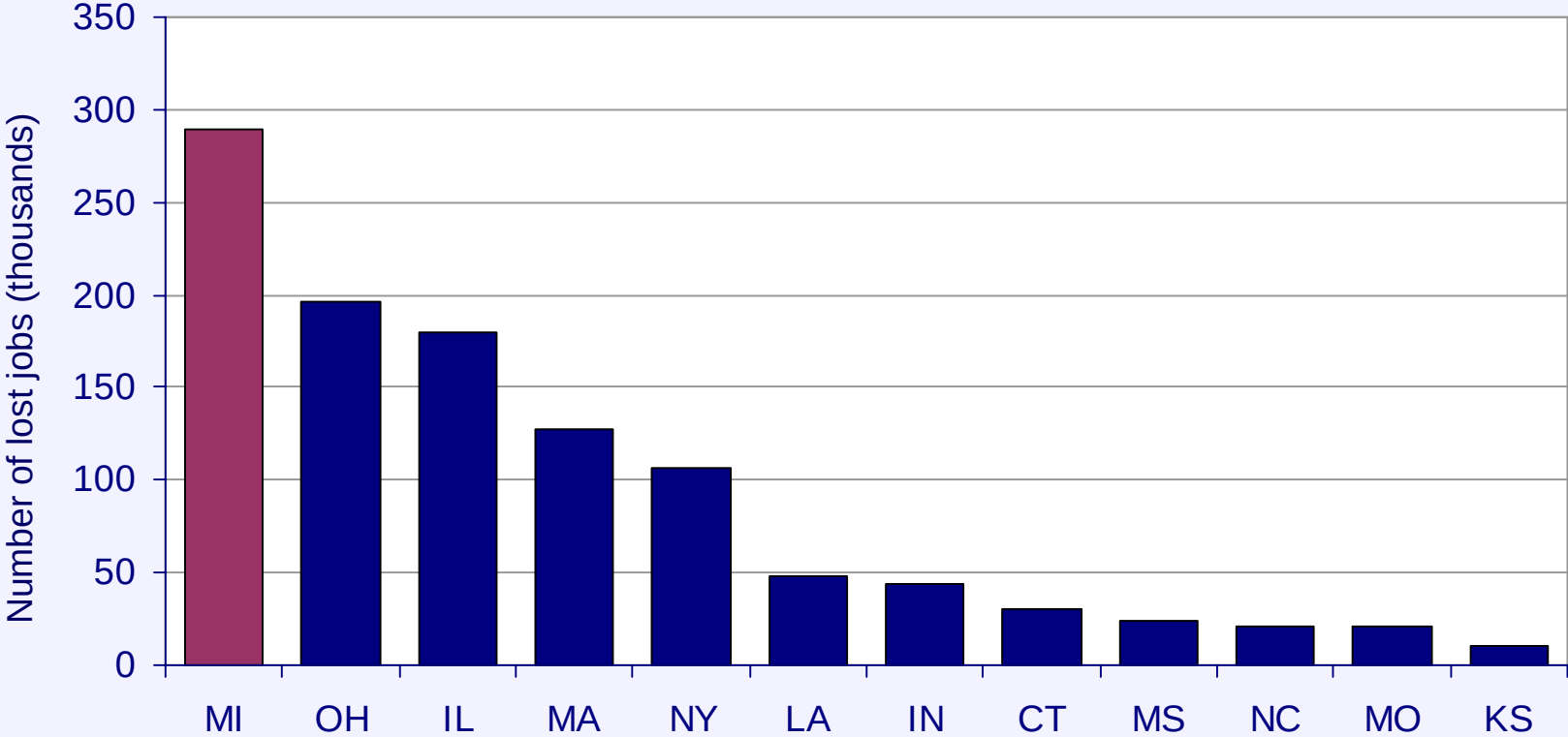
Witness: David E. Dismukes, Ph.D.

Exhibit: AG-1



Job Losses by State
Total Since 2000

Case No.: U-14893
Witness: David E. Dismukes, Ph.D.
Exhibit: AG-2



Economic Outlook

Case No.: U-14893

Witness: David E. Dismukes, Ph.D.

Exhibit: AG-3

	<u>Real GDP Growth</u>		<u>Unemployment Rate</u>	
	<u>Previous</u>	<u>New</u>	<u>Previous</u>	<u>New</u>
	----- (%) -----		----- (%) -----	
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'.

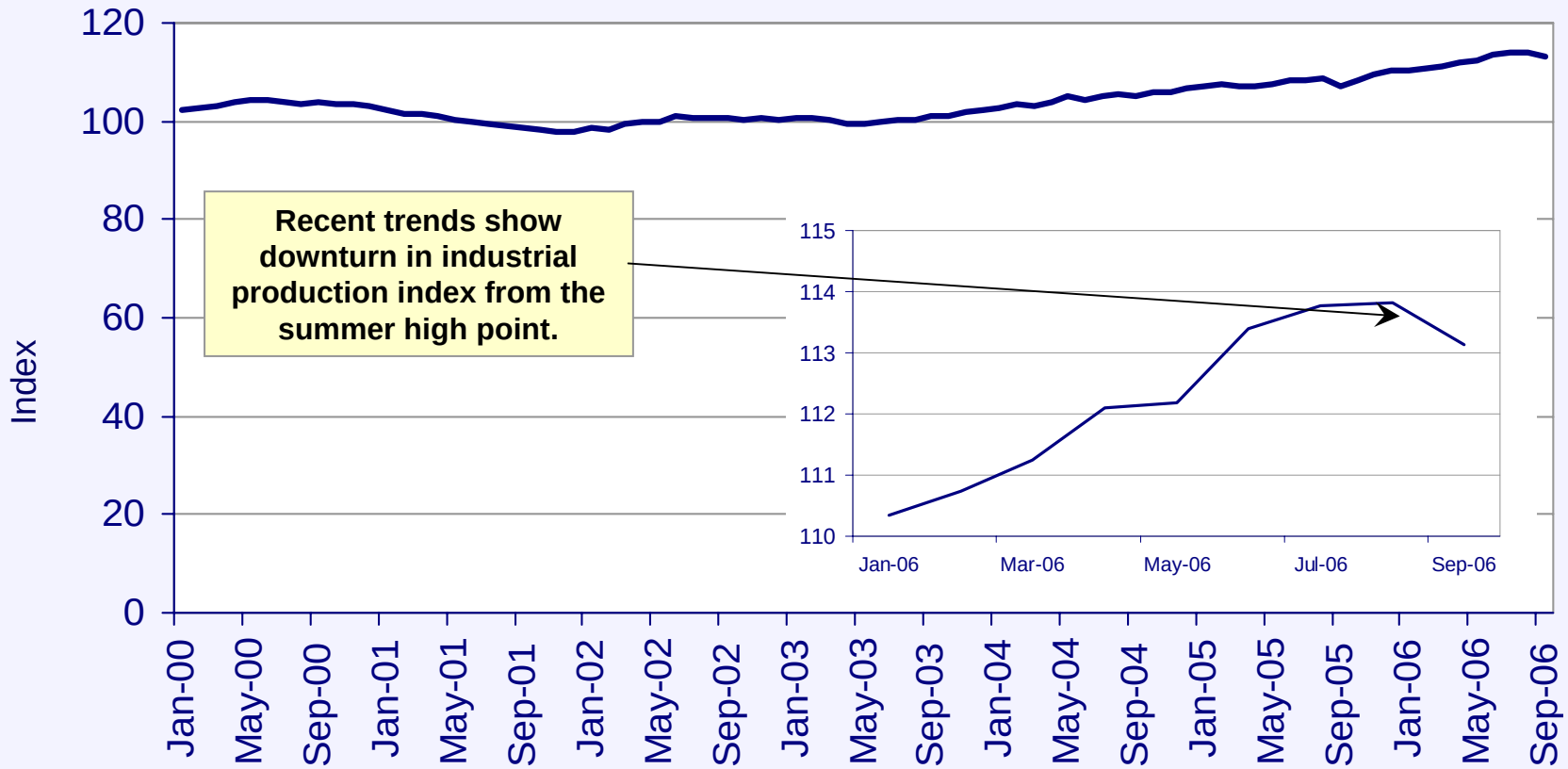
Source: Survey of Professional Forecasters, Federal Reserve Bank of Philadelphia, August 14, 2006

Industrial Production Index

Case No.: U-14893

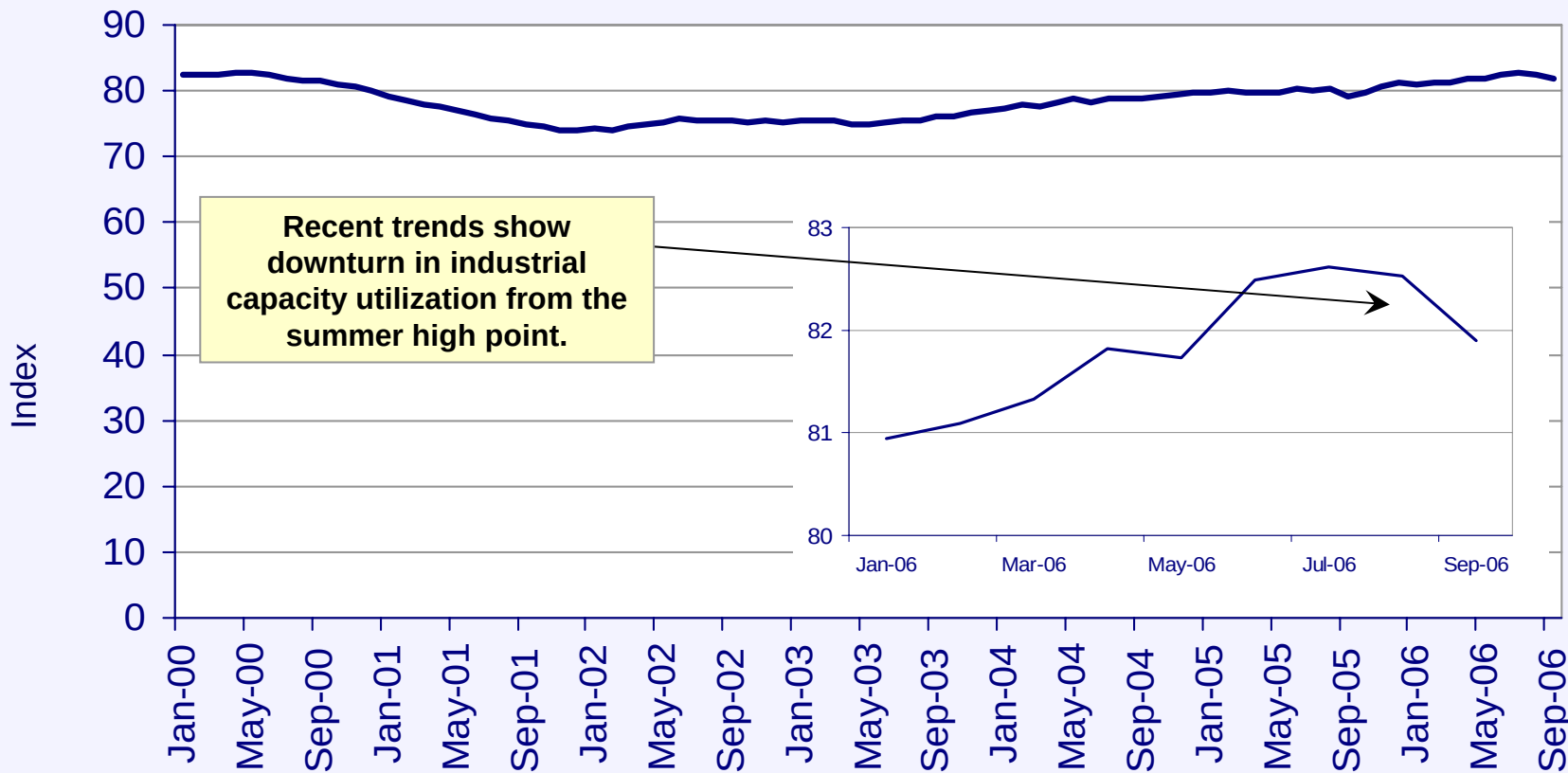
Witness: David E. Dismukes, Ph.D.

Exhibit: AG-4



Manufacturing Capacity Utilization

Case No.: U-14893
Witness: David E. Dismukes, Ph.D.
Exhibit: AG-5



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]

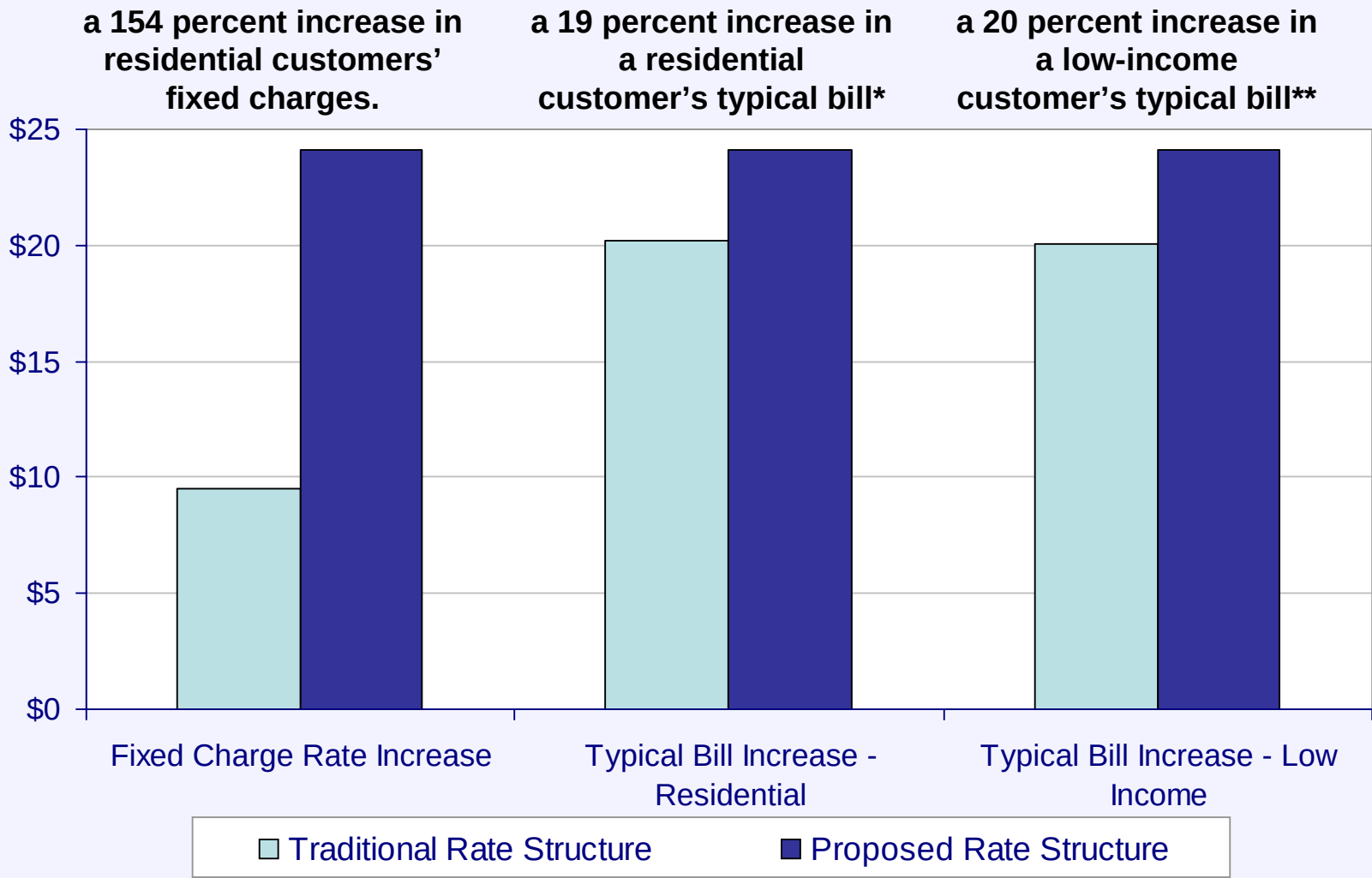
“Also, adding new customers to the Company's system appears to be a struggle in the current Michigan economic environment and does not necessarily solve the problem.” [Direct Testimony and Exhibit of Malcolm R. Ketchum, 20: 20-22]

“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:



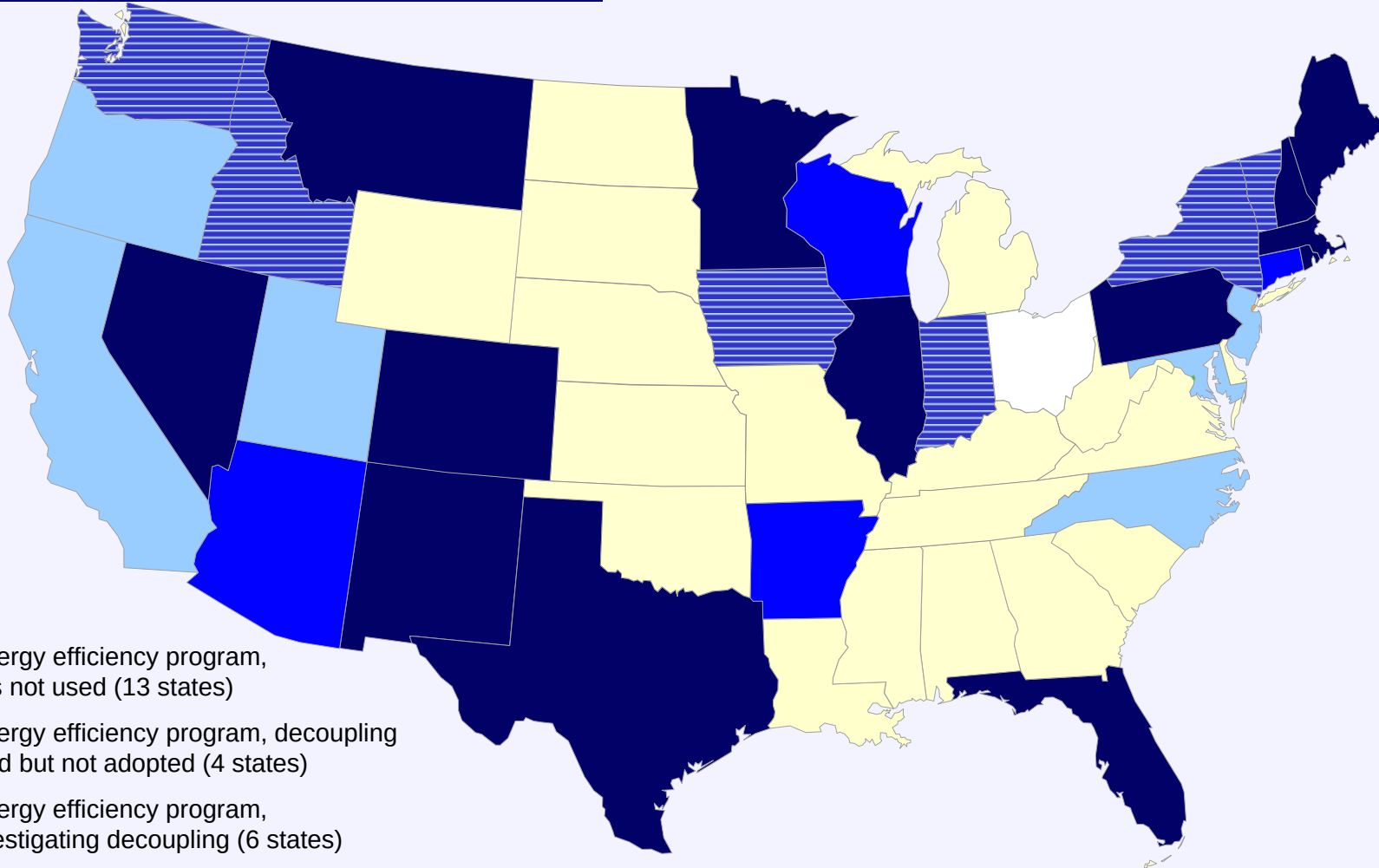
Note: *Assumes typical usage of 105.343 Mcf/year or 8.78 Mcf/month; **Assumes typical usage of 103.45 Mcf/year or 8.62 Mcf/month; slide represents changes in typical distribution service bill (non-fuel portion of bill); and calculations do not include LAUF charges.

States with Energy Efficiency Programs – Decoupling Status

Case No.: U-14893

Witness: David E. Dismukes, Ph.D.

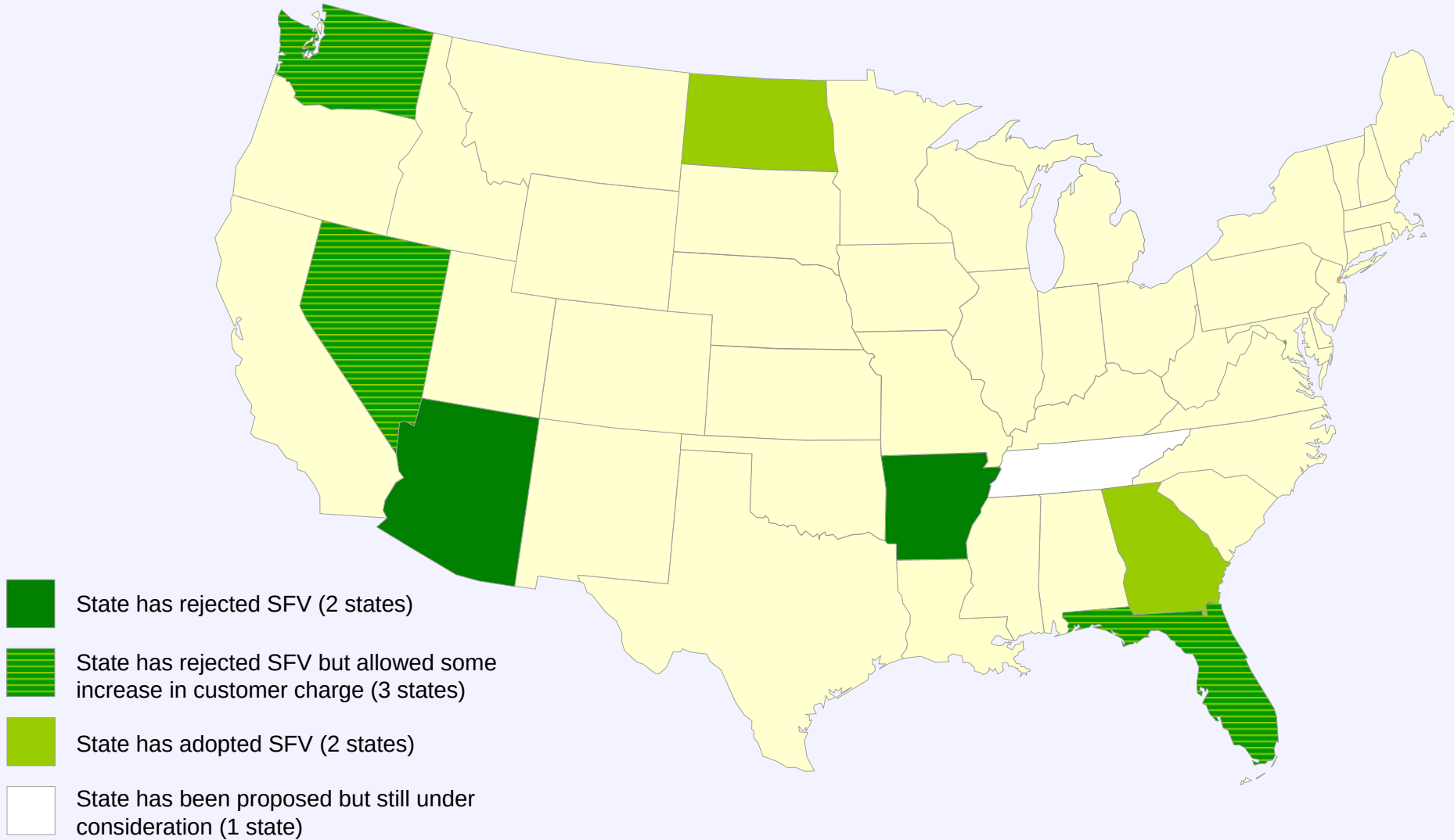
Exhibit: AG-8



Note: In Connecticut, the electric utilities do not have decoupling, but two natural gas LDCs have a partial decoupling mechanism in connection with their energy efficiency programs for low-income customers (a conservation adjustment mechanism).

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

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	Percent Change	15-Year Normalized	Percent Change
1996	123.9		124.9		N/A	
1997	122.1	-1.4%	120.1	-3.8%	N/A	
1998	114.2	-6.5%	112.5	-6.4%	153.6	
1999	115.6	1.2%	113.9	1.3%	154.3	0.5%
2000	118.1	2.2%	116.3	2.2%	165.4	7.2%
2001	111.5	-5.6%	109.8	-5.6%	160.5	-2.9%
2002	113.7	1.9%	111.8	1.8%	158.3	-1.4%
2003	111.8	-1.6%	110.0	-1.5%	154.2	-2.6%
2004	106.6	-4.7%	104.9	-4.6%	147.3	-4.5%
2005	104.6	-1.8%	103.1	-1.8%	143.4	-2.7%
7-Year Average	112.0	-1.2%	110.3	-1.2%	154.6	-0.9%
5-Year Average	109.6	-2.4%	107.9	-2.4%	152.8	-2.8%
3-Year Average	107.7	-2.3%	106.0	-2.3%	148.3	-2.7%

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	
1999	191,163	3.1%	218,351	2.9%
2000	197,447	3.3%	225,123	3.1%
2001	202,845	2.7%	230,732	2.5%
2002	207,475	2.3%	235,567	2.1%
2003	211,196	1.8%	239,481	1.7%
2004	214,630	1.6%	243,081	1.5%
2005	218,151	1.6%	246,588	1.4%
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%

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	<u>\$ 230,338,211</u>	<u>\$ 236,513,123</u>	<u>\$ 247,039,109</u>	<u>\$ 279,228,936</u>	<u>\$ 291,993,933</u>	<u>\$ 301,208,085</u>
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%

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.

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H

Re Southwest Gas Corporation
Docket No. G-01551A-04-0876
Decision No. 68487

Arizona Corporation Commission
February 23, 2006

OPINION and ORDER authorizing a natural gas local distribution company (LDC) to increase its rates and charges by \$49.345 million, reflecting a cost of equity of 9.50% and an average weighted cost of capital of 8.40%. The cost of equity includes a 30 basis point upward adjustment to the results of a discounted cash flow analysis in recognition of the higher risk faced by the LDC as compared to the proxy group. Capital costs are determined based on a hypothetical capital structure containing a 40% equity balance, even though the actual equity ratio of the LDC is more than 5 basis points lower. However, the commission sends a signal to the LDC that it must improve its actual capital structure by requiring the LDC to submit prior to its next rate case a re-capitalization plan explaining how it intends to achieve an equity ratio of 40%. Rates are designed to move towards cost-based rates as balanced by principles of gradualism, affordability, and conservation. Commission rejects as untenable a rate design proposal offered by the LDC that would have saddled a substantial number of residential customers with rate increases in excess of 100 percent. The base cost of gas -- currently included within the tariffed rate per therm for each class -- is set at zero so that the full commodity cost will be included in the purchased gas adjustor (PGA) rate. Commission finds that including the previously separate base cost of gas amount in the PGA will, once the change is explained to customers, enhance customer understanding of their bills and enable them to more easily track the separate components that go into the provision of gas service. Commission adopts a staff proposal to require the LDC to certify, under oath, through an affidavit attached to each adjustor report, that all information provided in the adjustor report is true and accurate to the best of his or her information and belief. The LDC is authorized to change its demand charge calculation formula for large commercial customers from a coincident peak method to a non-coincident peak method. Commission finds that the non-coincident peak measurement will take some of the risk of revenue recovery out of rates while reflecting value to customers on an annual basis. Commission rejects a decoupling proposal that would have insulated the LDC from risk associated with declining gas usage through the implementation of a conservation margin tracker (CMT). The CMT would, the commission finds, provide the LDC with a guaranteed method of recovering authorized revenues -- a result that neither the law nor sound public policy requires. Nonetheless, the commission encourages the LDC to work with other parties to develop an alternative decoupling mechanism for consideration in future

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proceedings.

Commission approves an equal sharing between ratepayers and shareholders of ongoing costs of complying with the Sarbanes-Oxley Act of 2002. It finds that the improved internal auditing controls required by Sarbanes-Oxley benefit both shareholders and ratepayers. Initial assessment and review costs associated with compliance with Sarbanes-Oxley are disallowed as non-recurring. The cost of a management incentive compensation program are shared equally between ratepayers and shareholders based on a finding that both groups derive benefits from the goals of the incentive program. However, departing from past practice, the commission disallows the costs of a supplemental executive retirement plan. Commission finds that expenses incurred by the LDC to comply with the federal Pipeline Safety Improvement Act should be borne equally by shareholders and ratepayers, with the ratepayer share collected through a surcharge mechanism. Commission declines to adjust accumulated deferred income taxes to recognize the effect of a new Internal Revenue Service regulation that went into effect nearly a year after the end of the test year. In rejecting the proposed adjustment, which would increase rate base, the commission explains that the LDC made an entirely voluntary decision in 2002 to change its accounting methodology for self constructed assets, and that it is this voluntary decision that has caused the LDC to now make accounting changes due to the new IRS regulation. Moreover, the commission finds federal Energy Policy Act of 2005 will result in increase deferred taxes, and thus decrease rate base. The LDC is authorized to recover dues paid to the American Gas Association, as adjusted to exclude that portion of dues directly attributable to marketing and lobbying. However, the LDC is directed to provide in its next rate case filing a clearer picture of AGA functions and how the activities of the AGA provide specific benefits to the LDC and its Arizona customers.

P.U.R. Headnote and Classification

1.

VALUATION

s192.1

Az.C.C. 2006

[ARIZ.] Accumulated deferred income taxes -- Proposed adjustment for Internal Revenue Service rule change -- Grounds for rejection -- Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

2.

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VALUATION

s281

Az.C.C. 2006

[ARIZ.] Natural gas local distribution company -- Rate base adjustment for completed construction not classified -- Grounds for allowing.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

3.

VALUATION

s187

Az.C.C. 2006

[ARIZ.] Pipe replacement projects -- Write-off for defective pipe -- Rejection of proposed retroactive modification of write-off schedule -- Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

4.

VALUATION

s281

Az.C.C. 2006

[ARIZ.] Natural gas local distribution company -- Pipe replacement projects -- Write-off for defective pipe -- Rejection of proposed retroactive modification of write-off schedule.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

5.

VALUATION

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s275

Az.C.C. 2006

[ARIZ.] Pipe replacement projects -- Write-off for defective pipe -- Rejection of proposed retroactive modification of write-off schedule -- Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

6.

VALUATION

s281

Az.C.C. 2006

[ARIZ.] Natural gas local distribution company -- Summary of rate base adjustments -- Approved original cost rate base -- Approved fair value rate base.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

7.

EXPENSES

s95

Az.C.C. 2006

[ARIZ.] Salaries and wages -- Employees engaged in marketing activities -- Partial disallowance based on estimate of time devoted to marketing -- Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

8.

EXPENSES

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s26

Az.C.C. 2006

[ARIZ.] Sales and marketing wages -- Partial disallowance based on estimate of employee time devoted to marketing -- Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

9.

EXPENSES

s99

Az.C.C. 2006

[ARIZ.] Wages -- Annualization of test year and post-test year increases -- Avoiding mismatch of revenues and expenses -- Increases applied only to employees employed during test year -- Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

10.

EXPENSES

s48

Az.C.C. 2006

[ARIZ.] Trade association dues -- American Gas Association -- Partial disallowance -- Removal of portion of dues directly attributable to marketing and lobbying -- Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

11.

EXPENSES

s88

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Az.C.C. 2006

[ARIZ.] Lobbying costs -- Exclusion from rates -- Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

12.

EXPENSES

s125

Az.C.C. 2006

[ARIZ.] Natural gas local distribution company -- Pipeline Safety Improvement Act of 2002 -- Compliance costs -- Transmission Integrity Management Program -- Equal sharing between ratepayers and shareholders -- Surcharge recovery mechanism.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

13.

RATES

s380

Az.C.C. 2006

[ARIZ.] Natural gas -- Special factors -- Pipeline Safety Improvement Act of 2002 -- Compliance costs -- Transmission Integrity Management Program -- Equal sharing between ratepayers and shareholders -- Surcharge recovery mechanism.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

14.

EXPENSES

s28

Az.C.C. 2006

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[ARIZ.] Financial reporting and auditing requirements -- Federal mandates -- Sarbanes-Oxley Act of 2002 -- Ongoing compliance costs -- Equal sharing between ratepayers and shareholders -- Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

15.

EXPENSES

s105

Az.C.C. 2006

[ARIZ.] Management incentive compensation -- Equal sharing between ratepayers and shareholders -- Recognition of benefits to both groups -- Natural gas local distribution company..

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

16.

EXPENSES

s105

Az.C.C. 2006

[ARIZ.] Extra benefits -- Supplemental executive retirement plan -- Exclusion from rates -- Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

17.

EXPENSES

s49

Az.C.C. 2006

[ARIZ.] Pensions -- Supplemental executive retirement plan -- Exclusion from

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rates -- Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

18.

EXPENSES

s15

Az.C.C. 2006

[ARIZ.] Reasonableness -- Miscellaneous expenses not necessary for provisioning of gas service -- Disallowance from rates -- Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

19.

EXPENSES

s19

Az.C.C. 2006

[ARIZ.] Miscellaneous expenses not necessary for provisioning of gas service -- Calculation of disallowance -- Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

20.

EXPENSES

s15

Az.C.C. 2006

[ARIZ.] Test of reasonableness -- Presumptions -- Burden of proof.

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P.U.R. Headnote and Classification

21.

RATES

s120

Az.C.C. 2006

[ARIZ.] Reasonableness -- Presumptions -- Burden of proof.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

22.

RATES

s648

Az.C.C. 2006

[ARIZ.] Practice and procedure -- Evidence -- Presumptions -- Burden of proof.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

23.

EXPENSES

s125

Az.C.C. 2006

[ARIZ.] Natural gas -- Test-year operations -- Approved adjustments -- Local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

24.

REVENUES

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s5

Az.C.C. 2006

[ARIZ.] Natural gas -- Test year adjusted operating income -- Local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

25.

RETURN

s26.1

Az.C.C. 2006

[ARIZ.] Reasonableness -- Capital structure -- Hypothetical structure containing 40% equity -- Need for re-capitalization plan for achieving actual equity ratio of 40% -- Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

26.

RETURN

s26.4

Az.C.C. 2006

[ARIZ.] Reasonableness -- Cost of common equity -- Positions of the parties -- Natural gas rate proceeding.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

27.

RETURN

s26.4

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Az.C.C. 2006

[ARIZ.] Reasonableness -- Cost of common equity -- Estimation methodology -- Primary reliance on discounted cash flow model -- Other financial models used as check on reasonableness -- Upward adjustment for higher risk than proxy group -- Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

28.

RETURN

s44

Az.C.C. 2006

[ARIZ.] Reasonableness -- Factors considered -- Risk -- Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

29.

RETURN

s4

Az.C.C. 2006

[ARIZ.] Jurisdiction, powers, and duties -- State commission -- To establish reasonable rate of return -- Legal standard.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

30.

RETURN

s15

Az.C.C. 2006

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[ARIZ.] Reasonableness -- Legal standard -- Commission powers and duties.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

31.

RETURN

s26.3

Az.C.C. 2006

[ARIZ.] Reasonableness -- Cost of preferred equity -- Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

32.

RETURN

s26.2

Az.C.C. 2006

[ARIZ.] Reasonableness -- Cost of debt -- Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

33.

RETURN

s92

Az.C.C. 2006

[ARIZ.] Natural gas local distribution company -- Average weighted cost of capital -- Return on fair value rate base -- Reasonableness.

Re Southwest Gas Corporation

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P.U.R. Headnote and Classification

34.

RATES

s373

Az.C.C. 2006

[ARIZ.] Natural gas local distribution company -- Authorized increase -- Method of calculation.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

35.

RATES

s380

Az.C.C. 2006

[ARIZ.] Natural gas -- Special factors -- Proposed decoupling of revenues from sales -- Conservation margin tracker -- Grounds for rejection -- Local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

36.

REVENUES

s5

Az.C.C. 2006

[ARIZ.] Natural gas local distribution company -- Proposed decoupling of margin from customer usage -- Conservation margin tracker -- Grounds for rejection.

Re Southwest Gas Corporation

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37.

AUTOMATIC ADJUSTMENT CLAUSES

s47

Az.C.C. 2006

[ARIZ.] Conservation margin tracker -- Decoupling of margin from customer usage
-- Grounds for rejection -- Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

38.

CONSERVATION

s1

Az.C.C. 2006

[ARIZ.] Natural gas local distribution company -- Promotion of conservation --
Proposed decoupling of margin from customer usage -- Grounds for rejection.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

39.

RATES

s143

Az.C.C. 2006

[ARIZ.] Reasonableness -- Allocation of margin among customer classes -- Factors
considered -- Cost of service -- Affordability -- Gradualism -- Appropriate price
signals -- Conservation goals.

Re Southwest Gas Corporation

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RATES

s373

Az.C.C. 2006

[ARIZ.] Natural gas rate design -- Allocation of margin among customer classes -- Factors considered -- Cost of service -- Affordability -- Gradualism -- Appropriate price signals -- Conservation goals.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

41.

RATES

s385

Az.C.C. 2006

[ARIZ.] Natural gas rate design -- Single family residential service -- Increased basic monthly charge -- Two-tier commodity rate -- Summer/winter first block differential -- Movement toward cost-based rates -- Balance with principles of gradualism affordability, and conservation -- Local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

42.

RATES

s385

Az.C.C. 2006

[ARIZ.] Natural gas rate design -- Creation of multi-family residential service class -- Recognition of lower cost to serve -- Local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

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RATES

s385

Az.C.C. 2006

[ARIZ.] Natural gas rate design -- Low-income residential service -- Retention of basic monthly charge and winter usage discount -- Local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

44.

RATES

s385

Az.C.C. 2006

[ARIZ.] Natural gas rate design -- Residential gas air conditioning -- Increase to summer second block -- Local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

45.

RATES

s384

Az.C.C. 2006

[ARIZ.] Natural gas rate design -- Master metered mobile home park service -- Increased basic monthly and volumetric charges -- Movement toward cost of service -- Gradualism and fairness -- Local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

46.

RATES

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s384

Az.C.C. 2006

[ARIZ.] Natural gas rate design -- Armed forces schedule -- Elimination --
Transfer of customers to large general service class -- Local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

47.

RATES

s384

Az.C.C. 2006

[ARIZ.] Natural gas rate design -- Small commercial customers -- Creation of new
sub-class -- Mitigation of increase -- Local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

48.

RATES

s382

Az.C.C. 2006

[ARIZ.] Natural gas rate design -- Large commercial customers -- Demand charge
calculation formula -- Non-coincident peak method -- Reduced risk of revenue
recovery -- Reflection of value to customers -- Local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

49.

RATES

s384

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Az.C.C. 2006

[ARIZ.] Natural gas rate design -- Gas service for compression on customer premises -- Basic monthly charge increases -- Movement toward cost of service -- Gradualism -- Local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

50.

RATES

s384

Az.C.C. 2006

[ARIZ.] Natural gas rate design -- Cogeneration gas service -- Proposed size restriction -- Grounds for denial -- Local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

51.

RATES

s384

Az.C.C. 2006

[ARIZ.] Natural gas rate design -- Small essential agricultural user service -- Proposed closing of tariff to new customers -- Grounds for denial -- Local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

52.

RATES

s384

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[ARIZ.] Natural gas rate design -- Engine gas service -- Agricultural irrigation -- On-peak charge increase -- Potential loss of customers to electricity no bar to increase -- Local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

53.

RATES

s382

Az.C.C. 2006

[ARIZ.] Natural gas rate design -- Demand and load -- Engine gas service -- Agricultural irrigation -- On-peak charge increase -- Potential loss of customers to electricity no bar to increase -- Local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

54.

RATES

s373

Az.C.C. 2006

[ARIZ.] Natural gas -- Tariff price setting -- Billing determinant calculations -- Appropriate methodology -- Local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

55.

RATES

s373

Az.C.C. 2006

[ARIZ.] Natural gas -- Commodity rate -- Base cost of gas set at zero --

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Inclusion of full commodity cost in purchased gas adjustor mechanism -- Local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

56.

AUTOMATIC ADJUSTMENT CLAUSES

s11

Az.C.C. 2006

[ARIZ.] Purchased gas adjustor mechanism -- Incorporation of full commodity cost -- Elimination from base rates -- Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

57.

AUTOMATIC ADJUSTMENT CLAUSES

s11

Az.C.C. 2006

[ARIZ.] Purchased gas adjustor mechanism -- Bank balance trigger level increase -- Corresponding increase in per therm adjustment band -- Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

58.

AUTOMATIC ADJUSTMENT CLAUSES

s11

Az.C.C. 2006

[ARIZ.] Purchased gas adjustor mechanism -- Monthly reports -- Officer certification requirement -- Natural gas local distribution company.

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Re Southwest Gas Corporation

P.U.R. Headnote and Classification

59.

AUTOMATIC ADJUSTMENT CLAUSES

s59

Az.C.C. 2006

[ARIZ.] Practice and procedure -- Purchased gas adjustor mechanism -- Monthly reports -- Officer certification requirement -- Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

60.

PAYMENT

s62

Az.C.C. 2006

[ARIZ.] Security for payment -- Customer deposits -- Interest rate -- Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

61.

SERVICE

s332

Az.C.C. 2006

[ARIZ.] Customer service -- Schedule for service -- Four-hour service window -- Natural gas local distribution company.

Re Southwest Gas Corporation

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P.U.R. Headnote and Classification

62.

RATES

s125

Az.C.C. 2006

[ARIZ.] Affordability -- Customers with financial difficulties -- Voluntary contributions by other customers -- Energy Share program -- Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

63.

PAYMENT

s17

Az.C.C. 2006

[ARIZ.] Billing and collections -- Customers with financial difficulties -- Voluntary contributions by other customers -- Energy Share program -- Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

64.

EXPENSES

s119.1

Az.C.C. 2006

[ARIZ.] Research and development -- Contributions to Gas Technology Institute and other research entities -- Recovery through surcharge -- Natural gas local distribution company.

Re Southwest Gas Corporation

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P.U.R. Headnote and Classification

65.

RATES

s380

Az.C.C. 2006

[ARIZ.] Natural gas -- Special factors -- Contributions to Gas Technology Institute and other research entities -- Recovery through surcharge -- Natural gas local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

66.

CONSERVATION

s1

Az.C.C. 2006

[ARIZ.] Natural gas -- Demand-side management -- Energy efficiency programs -- Low-income energy conservation -- Funding level -- Local distribution company.

Re Southwest Gas Corporation

P.U.R. Headnote and Classification

67.

EXPENSES

s19

Az.C.C. 2006

[ARIZ.] Demand-side management -- Energy efficiency programs -- Low-income energy conservation -- Funding level -- Natural gas local distribution company.

Re Southwest Gas Corporation

APPEARANCES: Mr. Andrew W. Bettwy, Ms. Karen S. Haller and Mr. Justin Lee Brown, on behalf of Southwest Gas Corporation; Mr. Scott S. Wakefield, on behalf of the

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Residential Utility Consumer Office; Mr. Walter Meek, on behalf of the Arizona Utility Investors Association; Mr. Peter Q. Nyce, Jr., on behalf of the United States Department of Defense; Mr. Timothy M. Hogan, Arizona Center for Law in the Public Interest, on behalf of Southwest Energy Efficiency Project and Natural Resources Defense Council; Ms. Laura Sixkiller, ROSHKA, DEWULF & PATTEN, PLC, on behalf of Tucson Electric Power Company; and Mr. Jason Gellman and Ms. Diane Targovnik, Staff Attorneys, Legal Division, on behalf of the Utilities Division of the Arizona Corporation Commission.

Before Hatch-Miller, chairman, and Mundell, Spitzer, Gleason, and Mayes, Commissioners, and Nodes, administrative law judge.

BY THE COMMISSION:

OPINION AND ORDER

On December 9, 2004, Southwest Gas Corporation ('Southwest Gas' or 'Company ') filed with the Arizona Corporation Commission ('Commission') an application for a rate increase.

On January 7, 2005, the Commission's Utilities Division Staff ('Staff') filed a Letter of Insufficiency.

On January 26, 2005, Staff filed a Letter of Sufficiency indicating that Southwest Gas' application met the sufficiency requirements outlined in Arizona Administrative Code ('A.A.C.') R14-2-103, and classifying the Company as a Class A utility.

By Procedural Order issued February 7, 2005, procedural timeframes were established and a hearing was scheduled to commence on October 3, 2005.

Intervention was granted to the Residential Utility Consumer Office ('RUCO '); the Arizona Utility Investors Association ('AUIA'); the United States Department of Defense ('DOD'); Southwest Energy Efficiency Project ('SWEEP ') and the Natural Resources Defense Council ('NRDC') (collectively 'SWEEP/ NRDC'); Yuma Cogeneration Associates ('YCA'); Arizona Community Action Association ('ACAA'); Arizona Public Service Company ('APS'); and Tucson Electric Power Company ('TEP').

With its application, Southwest Gas filed the Direct testimony of Jeffrey W. Shaw, Christina A. Palacios, Steven M. Fetter, Christy M. Berger, James L. Cattnach, Vivian E. Scott, A. Brooks Congdon, Edward B. Giesecking, Randi L. Aldridge, Robert A. Mashas, Frank J. Hanley, and Theodore K. Wood.

Pursuant to the revised procedural schedule established by Procedural Order issued March 10, 2005, on July 26, 2005, RUCO filed the Direct testimony of Marylee Diaz Cortez, William A. Rigsby, and Rodney L. Moore; YCA filed the Direct testimony of Jeffrey L. Hoffman; AUIA filed the Direct testimony of Walter W. Meek; ACAA filed the Direct testimony of Brian Babiars (July 20, 2005); SWEEP/NRDC

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filed the Direct testimony of Jeff Schlegel; and Staff filed the Direct testimony of Stephen G. Hill, Jim Dorf, Dennis Rogers, Robert Miller, William Gehlen, Prem Bahl, William Musgrove, Bob Gray, and Steve Irvine.

On August 23, 2005, Southwest Gas filed the Rebuttal testimony of Ms. Palacios, Mr. Fetter, Ms. Scott, Mr. Congdon, Mr. Giesecking, Ms. Aldridge, Mr. Mashas, Mr. Hanley, Mr. Wood, William N. Moody, Marti Marek, Robert M. Johnson, and Lisa E. Moses.

On September 13, 2005, RUCO filed the Surrebuttal testimony of Ms. Diaz Cortez, Mr. Rigsby, and Mr. Moore; AUIA filed the Surrebuttal testimony of Mr. Meek; SWEEP/NRDC filed the Surrebuttal testimony of Mr. Schlegel; DOD filed the Surrebuttal testimony of Dan L. Neidlinger; and Staff filed the Surrebuttal testimony of Mr. Hill, Mr. Dorf, Mr. Rogers, Mr. Gehlen, Mr. Musgrove, Mr. Gray and Mr. Irvine.

On September 23, 2005, Southwest Gas filed the Rejoinder testimony of Ms. Palacios, Mr. Fetter, Mr. Cattanach, Ms. Scott, Mr. Congdon, Mr. Giesecking, Mr. Moody, Ms. Marek, Ms. Moses, Ms. Aldridge, Mr. Mashas, Mr. Hanley, and Mr. Wood.

On September 26, 2005, a prehearing procedural conference was conducted to address order of testimony and exhibits.

The evidentiary hearing was commenced as scheduled on October 3, 2005, and additional hearing days were held on October 4, 5, 6, 7, and 11, 2005.

On October 21, 2005, Southwest Gas filed a substitute Exhibit A-50 (Annual Consumption Graph for Low Income and Non-Low Income Residential Customers) and Exhibit A-52 (information regarding the Company's Management Incentive Plan), a portion of which was submitted under seal.

On November 4, 2005, Southwest Gas filed Exhibit A-53 (compilation of regulatory commission orders from other states addressing decoupling mechanisms) and Exhibit A-54 (summary of Southwest Gas' revised position on cost of equity and rate of return).

Initial Post-Hearing Briefs were filed by DOD on October 31, 2005, by RUCO on November 3, 2005, and on November 4, 2005 by Southwest Gas, SWEEP/NRDC, AUIA, and Staff.

Reply Briefs were filed on November 14, 2005 by Southwest Gas, RUCO, SWEEP/ NRDC, and Staff.

On November 23, 2005, Southwest Gas filed a Supplement to its Reply Brief.

Rate Application

According to the Company's application, as modified, in the test year ended

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August 31, 2004 Southwest Gas had adjusted operating income of \$46,775,622 on an adjusted Original Cost Rate Base ('OCRB') of \$943,110,070, for a 4.96 percent rate of return. Southwest Gas requests a revenue increase of \$66,898,342. Staff recommends a rate increase of \$51,625,135, and RUCO recommends an increase of \$48,506,079. A summary of the parties' positions [FN1] follows:

.ps 9

	Company Proposed	Staff Proposed	RUCO Proposed
ORIGINAL COST			
Adjusted Rate Base	\$943,110,070	\$924,927,566	\$919,607,846
Rate of Return	9.24%	8.40%	8.64%
Req'd Operating Inc.	87,140,541	77,693,916	79,478,947
Op. Income Available	46,775,622	46,644,274	50,211,496
Operating Inc. Def.	40,364,919	31,049,641	29,267,452
Rev.Conver. Factor	1.6573	1.6627	1.6573
Gross Rev. Increase	66,898,342	51,625,135	48,506,079
FAIR VALUE			
Adjusted Rate Base	\$1,189,807,002	\$1,418,205,879	\$1,164,944,249
Rate of Return	7.32%	6.63%	6.82%
Req'd Operating Inc.	87,140,541	77,693,916	79,478,947
Op. Income Available	46,775,622	46,644,274	50,211,496
Operating Inc. Def.	40,364,919	31,049,641	29,267,452
Rev.Conver. Factor	1.6573	1.6627	1.6573
Gross Rev. Increase	66,898,342	51,625,135	48,506,079

REVENUE REQUIREMENT

Rate Base Issues

Southwest Gas proposes an OCRB of \$943,110,070 in this proceeding. Staff proposes an OCRB of \$924,927,566, and RUCO recommends an OCRB of \$919,607,846. Each of the disputed issues regarding rate base items is discussed below.

Deferred Income Taxes

[1] Southwest Gas has proposed an adjustment to accumulated deferred income taxes that would result in an increase of more than \$21 million to the Company's rate base. According to Southwest Gas, the deferred tax adjustment is necessary due to new regulations enacted by the Internal Revenue Service ('IRS') on August 3, 2005 which now require the Company to include in income in 2005 and 2006 the cumulative tax deduction taken under the prior uniform capitalization ('UNICAP') rules (IRS Code Section 263A) with respect to the simplified service cost method ('SSCM') for self-constructed assets (Ex. A-27, at 6). This deferred tax adjustment is necessitated by the Company's voluntary election in 2002 to change from its historical method of accounting to SSCM.

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Southwest Gas argues that the deferred tax adjustment is proper because the new IRS regulation is known and measurable, and because the change puts the Company in a similar position to where it would have been had it not made the election in 2002. The Company claims that its position is consistent with Commission precedent granting recognition of post-test year rate base adjustments where the impact is known and measurable, and is comparable to Staff's recommendation to recognize changes to property tax expenses that are required by post-test year legislation.

Staff disputes the Company's contention that the proposed deferred tax adjustment is proper in this proceeding. Staff argues that the deferred income tax adjustment proposed by Southwest Gas is due entirely to the Company's voluntary decision in 2002 to change its accounting methodology to the SSCM (Ex. S-6, at 2; Tr. 499-500). Staff also claims that the IRS regulations cited by Southwest Gas are temporary rules and the 2005 Energy Policy Act is likely to increase the amount of the Company's deferred taxes, thereby reducing rate base and offsetting the new IRS rule.

RUCO also opposes the Company's proposed adjustment, arguing that the IRS rule change occurred nearly a year after the end of the test year. RUCO further contends that Southwest Gas failed to include this proposal in its initial application and waited until Rebuttal testimony to propose the adjustment. RUCO also sides with Staff's argument that the IRS rules are temporary and subject to amendment before being made final. As a result, RUCO asserts that the IRS rule change does not meet the known and measurable standard employed for other post-test year adjustments.

We agree with Staff and RUCO that recognition of the new IRS regulation is not proper in this proceeding. As Staff points out, Southwest Gas made an entirely voluntary decision in 2002 to change its accounting methodology for self-constructed assets to SSCM, and it is that voluntary election that has caused the Company to now make accounting changes due to the new IRS regulation. The Company's witness, Lisa Moses, admitted that the 2005 Energy Policy Act would result in an increase in deferred taxes, and thus a decrease in the Company's rate base, but she indicated that the Company had not quantified the impact of those changes. Although Ms. Moses stated that she does not believe the Energy Policy Act would have a significant impact on Southwest Gas, the Company did not present testimony to show how the Energy Policy Act, which is an equally known and measurable change in law, could have an offsetting effect on the Company's deferred tax liability and rate base (Tr. 495-497). We also believe RUCO's point is well taken, that Southwest Gas could have presented this proposal as part of its direct case to allow other parties more time to analyze the issue prior to the hearing. As a result, we will adopt Staff's position on this issue.

Completed Construction Not Classified

[2] The National Association of Regulatory Utility Commissioners' ('NARUC') Uniform System of Accounts ('USOA'), Section 106, provides the following description of the appropriate regulatory treatment for Completed Construction Not

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Classified ('CCNC'):

At the end of the year or such other date as a balance sheet may be required by the Commission, this account shall include the total of the balances of work orders for utility plant which has been completed and placed in service but which work orders have not been classified for transfer to the detailed utility plant accounts. (RUCO Ex. 9)

In its application, Southwest Gas proposed an adjustment to test year rate base to reflect its CCNC balance. Relying on the NARUC USOA section quoted above, RUCO argues that only work orders which have an in-service date that falls within the test year may be included in the adjustment for CCNC (RUCO Ex. 5, at 8). According to RUCO witness Rodney Moore, certain work orders that were included in the Company's CCNC adjustment were not in service by the end of the test year and should, therefore, be disallowed (RUCO Ex. 6, at 7-8).

Through her Rejoinder testimony, Company witness Randi Aldridge explained that 'the direct gas plant portion of the CCNC adjustment is plant that was serving test year customers at the end of the test year' and the proposed CCNC adjustment 'was made simply to match test year plant with test year customers ' (Ex. A-31, at 17-18). Ms. Aldridge also testified on cross-examination that although the Company's work order system may have only a single in-service date for an entire project, projects such as pipe replacements are completed incrementally to minimize customer outages, but all of the plant additions included in the CCNC account reflect pipe that was used and useful during the test year (Tr. 537-538, 589).

We agree with the Company's proposed CCNC adjustment. As Ms. Aldridge's testimony makes clear, only plant that was in service providing service to customers within the test year was included in the proposed CCNC adjustment. There is no evidence contrary to the Company's assertion that such plant was used and useful during the test year and we believe the Company's treatment of these plant accounts is consistent with the NARUC USOA and prior Commission decisions.

Pipe Replacement

[3-5] RUCO has proposed disallowance of certain requested pipe replacement projects from the Company's rate base pursuant to the terms of a prior Commission Order that addressed regulatory treatment of defective pipe [FN2] installed in the former Tucson Gas & Electric system, which was subsequently acquired by Southwest Gas. In Decision No. 58693 (July 7, 1994), the Commission adopted a Settlement Agreement between Southwest Gas, Staff, and RUCO which required Southwest Gas to write-off a certain percentage of the replacement cost of defective pipe, and provided that the pipe replacement percentage write-off amounts would decline annually until the amounts reached zero (Decision No. 58693, at 3-4; RUCO Ex. 3, at 5-6). RUCO witness Marylee Diaz Cortez testified that the Company has continued to make the required pipe replacement write-offs since the prior Decision but the Company seeks in this docket to cease certain of the write-offs (RUCO Ex. 3, at 6).

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In its application, Southwest Gas is requesting that the pipe write-off schedule required by Decision No. 58693 be modified to allow the affected write-offs to cease when the specific type of pipe reached an average life of 40 years. Thus, under the Company's proposal the 1960s steel pipe and the ABS pipe would no longer be subject to write-off and the scheduled write-offs for the Aldyl A and Aldyl HD pipe would cease in 2013 and 2020, respectively (Id.).

Although RUCO agrees that Southwest Gas is entitled to seek modification of the prior write-off requirements, RUCO disagrees with the Company's proposal to retroactively modify the write-off schedule starting in 2000. RUCO argues that Southwest Gas is required to comply with the requirements of Decision No. 58693 until such time as a subsequent Commission Order is issued modifying those requirements (Id. at 7-8). Ms. Diaz Cortez agreed that the Company's modified pipe replacement schedule, based on a 40-year life, should be permitted on a going-forward basis, but opposes the retroactive treatment proposed by the Company (Id.). Based on its position, RUCO recalculated the write-offs required by Decision No. 58693 and determined that the Company's proposed rate base should be reduced by \$1,982,686.

Southwest Gas contends that RUCO misinterpreted the data provided by the Company with respect to pipe replacement amounts. The Company cites to Exhibit A-47, a data request response provided to RUCO that shows the amount of Aldyl A, 1960s steel, and ABS pipe replaced between 2000 and 2004. The Company claims the data request response indicates the costs provided for pipe replacement are 'not necessarily for pipe replaced due to defective material or faulty installation practices' (Id.). However, the data request cited by Southwest Gas does not identify which costs are related to the prior Order's requirements. Company witness Robert Mashas testified that the Company disagrees with RUCO's recommendation because 1960s vintage steel pipe was never considered a defective material and was only included as part of the Settlement Agreement because it lacked cathodic protection, which has been installed on all of the Company's steel pipe since 1998 (Ex. A-33, at 16-17).

Contrary to the Company's assertions, neither the Settlement Agreement nor the Order adopting it mention cathodic protection for 1960s pipe as a distinguishing characteristic that would permit treatment that is different from the other types of pipe that were considered defective and required specific regulatory treatment. Rather, both the Settlement and the Order specifically state that 'In future Southwest rate cases for the Southern Division gas properties, Southwest shall exclude from rate base an additional portion of capitalized expenditures associated with replacements of Aldyl A, Aldyl HD, steel installed in the 1960's, and ABS pipe related to defective materials and/or installation' (Decision No. 58693, at 3).

Mr. Mashas also claims that the effective date of the new write-off should be January 1, 2000, the day after the end of the test year in the Company's last rate case. He contends that this retroactive application of the write-off percentages more accurately reflects the determination of the remedial portion of eligible

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pipe replacement expenditures (Id.). Mr. Mashas stated that the Commission has the authority to make the proposed adjustment retroactive to 2000, and that even RUCO agrees that the Commission has such authority.

Although we may have the legal authority to make the retroactive adjustment proposed by Southwest Gas, we are not inclined to exercise such authority if it is not in accordance with a valid binding Commission Order which adopted a Settlement Agreement to which Southwest Gas was a signatory party. The Company may not unilaterally alter the terms of a Settlement Agreement and Commission Order simply because it has an understanding of the terms of the agreement that may differ from the belief of another party. Rather, the Company could seek an amendment to the requirements of the prior Order if it believed the terms are no longer applicable, which it has properly done in this docket. However, we agree with RUCO that Southwest Gas must continue to comply with the requirements of the prior Order until such time as those requirements are modified by the Commission. Therefore, based on the weight of the evidence, and in accordance with the directives set forth in Decision No. 58693, we adopt RUCO's position on this issue and will reduce the Company's proposed rate base accordingly.

Summary of Rate Base Adjustments

[6] Based on the foregoing discussion, we adopt an adjusted OCRB of \$922,944,881 and a Fair Value Rate Base ('FVRB') of \$1,169,584,038.

	Commission Approved
6p	
ORIGINAL COST:	
6p	
Gas Plant in Service -- Staff	\$1,682,879,492
Less: Accumulated Depreciation	593,408,170
Net Plant in Service	1,089,471,322
6p	
Deductions:	
CIAC	7,027,372
Customer Meter Deposits	23,912,141
Deferred Income Tax Credits	136,468,076
6p	
Additions:	
Working Capital	881,148
Total OCRB	922,944,881
6p	
RCND RATE BASE:	
6p	
Gas Plant in Service -- Staff	\$2,439,429,196

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Less: Accumulated Depreciation	856,679,561
Net Plant in Service	1,582,749,635
6p	
Deductions:	
CIAC	7,027,372
Customer Meter Deposits	23,912,141
Deferred Income Tax Credits	136,468,076
6p	
Additions:	
Working Capital	881,148
Total RCND	1,416,223,194
6p	
FAIR VALUE RATE BASE:	
6p	
Gas Plant in Service -- Staff	\$2,061,154,344
Less: Accumulated Depreciation	725,043,866
Net Plant in Service	1,336,110,479
6p	
Deductions:	
CIAC	7,027,372
Customer Meter Deposits	23,912,141
Deferred Income Tax Credits	136,691,328
6p	
Additions:	
Working Capital	881,148
Total FVRB	1,169,584,038

Operating Income Issues

In the test year, the Company's adjusted operating revenues were \$322,865,978. In its Rebuttal Schedules, Southwest Gas reported adjusted test year operating expenses of \$276,090,356, and test year net operating income of \$46,775,622. As reported in its Surrebuttal Schedules, Staff's proposed adjusted test year operating expenses are \$276,221,704, resulting in test year operating income of \$46,644,274. RUCO's Surrebuttal Schedules show proposed adjusted test year total operating expenses of \$272,654,482, yielding test year operating income of \$50,211,496. The disputed expense adjustments are discussed below.

Sales and Marketing Wages for 37 Employees

[7, 8] RUCO witness Rodney Moore proposed disallowance of salaries and wages for 37 Southwest Gas employees who he claimed were engaged in sales, marketing and promotional activities. He claimed that ratepayers should not be required to fund

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the cost of such activities and he proposed removal of almost \$3 million in salaries from the Company's test year expenses (RUCO Ex. 5, at 15- 16). In his Surrebuttal testimony, Mr. Moore modified his recommendation to exclude the entirety of the 37 employees' wages, stating that 'RUCO would be willing to explore revisiting its position if a fair and reasonable quantification of the time/costs devoted solely to Customer complaint resolution and Regulatory affairs could be substantiated by the Company' (RUCO Ex. 6, at 18).

In her Rebuttal testimony, Company witness Christina Palacios disputed RUCO's analysis and stated that the Company had previously removed almost \$600,000 in promotional and marketing expenses, consistent with prior Commission Decisions. Ms. Palacios testified that the employees' wages that RUCO seeks to disallow are responsible for interacting with individual customers and developers seeking information regarding extension of gas service, as well as maintaining oversight until service is extended to a requesting property (Ex. A-5, at 2-6). Ms. Palacios asserted that the job duties of the employees in question include: advising customers on gas products and availability; coordinating new business processes; working with customers to determine technical needs and specifications; investigating and settling customer complaints; ensuring satisfactory customer service; participating in customer business meetings as consultants/advisors; establishing programs to educate customers; interpreting and applying tariffs to main/service extensions; ensuring adequate and timely coordination of services; negotiating contracts and special agreements; preparing studies and analyses; making presentations to trade allies or potential customers; and staying up to date on government regulations and technology changes within the industry (Id. at 4). Southwest Gas cites to Decision No. 64172 wherein the Commission denied RUCO's proposal to remove half of the costs associated with Southwest Gas' sales and marketing employees because 'these employees are necessary for processing a request for service ' (Decision No. 64172, at 10-11). The Company also cites to a decision by the United States Supreme Court in *West Ohio Gas Co. v. Public Utilities Com'n of Ohio*, 294 U.S. 63, 72 (1935), which held that '[w]ithin the limits of reason, advertising or development expenses to foster normal growth are legitimate charges upon income for rate purposes'

We agree with RUCO that a portion of the salaries of employees associated with sales, marketing, and promotional activities should be excluded from allowable test year expenses in this proceeding. It appears that the majority of these employees' time is dedicated to duties that enhance service to customers and potential customers, thereby providing benefits to both shareholders and ratepayers. However, by the Company's admission, a certain amount of these same employees' time is devoted to purely marketing or promotional activities that the Commission has previously found are expenses that should not be borne by ratepayers. For example, Ms. Palacios provided an estimate at the hearing that the employees in question devoted approximately 90 percent of their time to non-marketing duties, as described above, and approximately 10 percent to marketing activities (Tr. 109-110). In addition, Company witness Aldridge stated that approximately 17 percent of those same employees' compensation was obtained from the Company's Sales Incentive Plan (Tr. 573-574). Despite the admission by

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Company witnesses that at least some portion of these employees' time is devoted to sales and marketing activities, no attempt was made to allocate a portion of their wages out of test year expenses. Based on the best information in the record, we believe it is reasonable to perform such an allocation and we will therefore disallow 10 percent of the 37 employees' wages from test year expenses (i.e., \$289,243). In addition, we expect Southwest Gas in its next rate case to provide a detailed explanation of employee duties that are associated with sales, marketing, or promotional activities and offer a reasonable allocation of wage expense consistent with those duties.

Labor Annualization and 2005 Wage Increases

[9] In this proceeding, Southwest Gas has included in proposed test year expenses an annualization of wage increases that were given to employees in 2004, as well as wage increases granted in 2005 after the end of the test year. However, the Company included only wage increases for employees who were employed as of the end of the test year to avoid a mismatch (Ex. A-31, at 3-5; Tr. 543-545).

Although RUCO accepts the 2004 wage increase, it disputes the inclusion of the post-test year wage increase because it believes inclusion of the 2005 increase constitutes a double counting of such expenses (RUCO Ex. 6, at 11; Tr. 929- 930).

Staff witness Jim Dorf testified that Staff has accepted the reasonableness of including both the 2004 and 2005 wage increases because the costs are known and measurable (Tr. 1085).

We agree with Staff that the 2005 wage increase expense should be allowed because it is a known and measurable expense that is being incurred by the Company on a going-forward basis. Because the post-test year wage increase has been applied only to employees who were employed during the test year, there is no resulting mismatch of revenue and expenses.

American Gas Association Dues

[10, 11] The American Gas Association ('AGA') is a national trade association for natural gas distribution and transmission companies. During 2004, Southwest Gas paid dues to the AGA (Arizona portion) of \$211,934 (RUCO Ex. 5, RLM-9). The AGA provides services to its members in the following categories: Public Affairs; Communications; Corporate Affairs and International; General Counsel and Corporate Secretary; Regulatory Affairs; Marketing Development; Operating & Engineering Services; Policy & Analysis; Industry Finance & Administrative Programs; and General & Administrative Expense (Ex. A-30, RLA-3).

Although Southwest Gas claims that it has removed the amount of the dues that are attributable to the AGA's Marketing and Lobbying functions (1.54 percent and 2.10 percent, respectively), RUCO seeks an additional 39.09 percent disallowance (\$75,385) for the Public Affairs and Communications functions performed by the AGA (RUCO Ex. 5, RLM-9). According to RUCO witness Moore, the Communications category

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of AGA operations promotes the use of gas over other fuels, while the Public Affairs category provides members with information on legislative and regulatory developments, provides testimony, comments, and filings regarding legislative and regulatory activities, and lobbies on behalf of the industry (Id. at 21-22).

Southwest Gas witness Aldridge countered that the Communications and Public Affairs categories are appropriate AGA functions that should be recovered in test year expenses because the Company removed the amounts specifically associated with marketing and lobbying. Ms. Aldridge testified that the Communications function of the AGA includes developing informational materials for member companies and consumers and coordinating all media activity (Tr. 550). With respect to the Public Affairs function, the AGA described its activities as follows: 'The [AGA] monitored and represented the activities of Congress and Federal agencies that affected issues of importance to the natural gas industry and its customers. This division also monitored state and local legislative and regulatory trends. In 2002 its major federal, legislative and regulatory efforts were pipeline safety legislation and regulation, Federal funding for Low Income Home Energy Assistance Program (LIHEAP), federal funding for research, and national energy policy legislation.' (Ex. A-30, RLA-3).

We believe that the Company has demonstrated sufficiently that, having removed the portion of its AGA dues directly attributable to marketing and lobbying, the remainder of the AGA dues should be recoverable as legitimate test year expenses. Although the descriptions of AGA activities provided by the Company are somewhat nebulous, we find that Southwest Gas has met its burden of showing that the functions for which RUCO seeks exclusion have a benefit to the Company and its customers and should be allowed. However, in its next rate case filing the Company should provide a clearer picture of AGA functions and how the AGA's activities provide specific benefits to the Company and its Arizona customers.

Transmission Integrity Management Program Expenses

[12, 13] The federal Pipeline Safety Improvement Act of 2002 directed the Office of Pipeline Safety and the Research and Special Programs Administration divisions of the U.S. Department of Transportation to enact regulations creating standards for transmission pipeline risk analysis and adopting a pipeline integrity management program (Ex. A-32, at 19-21). In Arizona, Southwest Gas has identified approximately 335 miles of transmission facilities located in high consequence areas that are subject to the federal legislation (Ex. S-3, at 6-7). The Company's application in this docket includes an expense adjustment to recover costs associated with compliance with this legislation, which Southwest Gas calls its Transmission Integrity Management Program ('TRIMP'). The Company seeks to recover costs incurred prior to the effective date of the rates in this proceeding, as well as a representative level of ongoing costs that it expects to incur due to ongoing TRIMP activities (Id.). Although the Company initially sought to recover a higher level of TRIMP expenses, it subsequently agreed to RUCO's recommendation to amortize 2004 and 2005 TRIMP costs over 7 years (\$138,365 annually), with an additional test year allowance of \$603,677 annually (RUCO Ex. 3, MDC-5).

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Staff witness Dorf testified that although Staff encourages Southwest Gas to comply fully with the new pipeline safety regulations, Staff is concerned with the volatility of the Company's estimated compliance costs, as exemplified by a comparison of the Company's original estimate of more than \$12 million through 2009 compared to its revised estimate of just over \$3 million (Ex. S-4, at 5). Due to this fluctuation in the estimated ongoing compliance costs, as well as Staff's belief that the expenses should be borne jointly by shareholders and ratepayers, Mr. Dorf recommended establishment of a surcharge mechanism that would allow recovery through rates of half of the baseline direct assessment, direct examination, and maintenance and repair TRIMP-related costs (but not capital replacements). Staff proposes that the surcharge be labeled on customer bills as 'DOT Pipeline Safety Surcharge.' Staff's proposed surcharge would have annual adjustments after the first and second year, and would terminate at the end of the third year (Ex. S-3, at 11-14). Mr. Dorf explained that Staff's rationale for its recommendation is based on the following factors: 1) the Pipeline Safety Act of 2002 has significantly modified pipeline safety regulations; 2) the estimated costs of complying with the new regulations are significant; 3) initial assessments must be performed in a compressed time period; 4) current rates do not provide for recovery of these incremental costs; and 5) the costs are estimated at this time and are therefore inappropriate for inclusion in base rates (Id. at 12).

We agree with the reasoning expressed by Staff witness Dorf that TRIMP costs should be borne equally by shareholders and ratepayers, and a surcharge mechanism is the appropriate means of recovery. As Mr. Dorf stated at the hearing, recovery of TRIMP expenses through a surcharge would mitigate potential volatility in the program's costs especially given the long projection period for completing the first cycle of TRIMP costs (Tr. 1082). With respect to the split of TRIMP costs, we also agree with Staff that because the pipeline safety program benefits both shareholders and ratepayers, the TRIMP expenses should be shared equally. We will therefore adopt Staff's recommendation for treatment of TRIMP costs.

Sarbanes-Oxley Compliance Expenses

[14] Section 404 of the Sarbanes-Oxley Act of 2002 ('SOX') requires the establishment of an internal control structure and certain procedures for financial reporting, including a requirement that the company's annual report contain an internal control report (Ex. A-29, at 21-22). This legislation created the Public Company Accounting Oversight Board, and requires that publicly traded companies' external auditors attest to and report on management's assessment of the effectiveness of their internal controls and procedures. Companies were required to be in compliance with SOX by December 31, 2004 (Ex. S-3, at 15).

Southwest Gas seeks an adjustment to recover expenses related to the initial assessment and review of the Company's internal controls and additional post-test year expenses that it claims are necessary to fully implement SOX requirements, as well as estimated incremental and recurring compliance costs related to audit fees (Ex. A-30, at 9-13). Subsequent to filing its application, the Company updated its estimated compliance costs to reflect actual expenses, and Ms. Aldridge testified

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that those costs are reasonable in light of the Company's use of internal labor, including exempt employee labor for which overtime pay was not required (Id.).

Staff recommends an equal sharing of ongoing SOX compliance costs between ratepayers and shareholders based on its claim that the improved internal controls required by SOX provide a benefit to both groups. Staff witness Dorf stated that the SOX requirements protect ratepayers with improved compliance and benefits shareholders by protecting them from management impropriety (Staff Ex. 3, at 17). Mr. Dorf also testified that Staff recommends a 25 percent reduction of initial audit costs based on published reports by the American Institute of Certified Public Accountants that original estimates were overstated, and Staff recommends disallowance of the Company's proposed recovery of non-recurring implementation costs (Id.; Tr. 1085-1087).

Although it is important for Southwest Gas to comply fully with federally mandated audit and reporting requirements, we believe Staff's recommendation more accurately reflects the actual SOX compliance costs that will be incurred by the Company for the period that the rates set in this proceeding are in effect. As Mr. Dorf points out in his testimony, Staff's recommendation is based on numerous published articles that indicate there will be significant reductions to many companies' first year implementation and audit costs. Mr. Dorf cited to a white paper published by Enterprise Financial Consulting, LLP, which suggests numerous ways to reduce SOX costs in future years, and indicates that use of a compliance software application alone could save a minimum of 30 percent of the initial compliance costs (Ex. S-4, at 6).

We also agree with Staff's equal sharing of ongoing SOX compliance costs given the clear benefit that shareholders will receive in addition to ratepayer benefits. If anything, shareholders are likely to be greater beneficiaries of the SOX legislation because compliance with the new law will provide additional assurance that companies' financial statements have a higher degree of reliability. Indeed, ratepayers are at best only secondary beneficiaries of the SOX compliance procedures. We will therefore adopt Staff's position on this issue.

Management Incentive Program

[15] Southwest Gas provides compensation in addition to base salaries to certain eligible management employees through its Management Incentive Program ('MIP') based on achievement of the following five factors: 1) an improved customer-to-employee ratio when compared to the prior year; 2) a comparison of the Company's customer-to-employee ratio to its peer utilities; 3) the results of customer satisfaction surveys; 4) the achievement of a three-year return on equity ('ROE') target; and 5) a comparison of the Company's ROE to its peer utilities (Ex. A-33, at 7). Company witness Mashas claims that these five factors were designed to align customer and shareholder interests (Id.). Southwest Gas contends that achieving these goals increases productivity and helps the Company retain quality employees by deferring 60 percent of the MIP payout for three years (Id. at 6-11).

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RUCO proposes to reduce MIP expenses by 67 percent to recognize that shareholders receive the majority of benefits through achievement of the MIP performance targets, especially between rate cases. Ms. Diaz Cortez testified that amounts awarded under the MIP could be viewed as bonuses because the eligible individuals also receive wage and salary increases. She also stated that the annual amount of MIP compensation is not known and measurable because the payouts depend on reaching the performance goals (RUCO Ex. 3, at 20-23).

Staff also recommends reducing MIP expenses, but proposes an equal sharing between shareholders and ratepayers. Staff witness Dorf stated that shareholders and ratepayers stand to benefit from the performance goals, but added that there is no assurance that the award levels achieved during the test year will be repeated in future years (Ex. S-4, at 9-10).

Southwest Gas responds that MIP payouts should be considered part of the employees' overall compensation package and no party in the case has suggested that the employees' total pay is unreasonable, and that the Company is penalized by the Staff and RUCO proposals by putting part of its management's compensation at risk. According to Southwest Gas, if the Company put these amounts in the employees' base salary, Staff and RUCO would not claim that there should be a disallowance.

In Decision No. 64172, the Commission adopted Staff's recommendation regarding MIP expenses based on Staff's claim that two of the five performance goals were tied to return on equity and thus primarily benefited shareholders. We believe that Staff's recommendation for an equal sharing of the costs associated with MIP compensation provides an appropriate balance between the benefits attained by both shareholders and ratepayers. Although achievement of the performance goals in the MIP, and the benefits attendant thereto, cannot be precisely quantified there is little doubt that both shareholders and ratepayers derive some benefit from incentive goals. Therefore, the costs of the program should be borne by both groups and we find Staff's equal sharing recommendation to be a reasonable resolution.

Supplemental Executive Retirement Plan

[16, 17] Southwest Gas offers a Supplemental Executive Retirement Plan ('SERP') to the Company's officers. Company witness Mashas testified that the SERP is necessary 'to ensure that the retirement and deferred compensation portions of [the officers'] total compensation are on parity with all other employees of Southwest whose retirement distribution is not impacted by certain IRS regulations' (Ex. A-33, at 3). Mr. Mashas claims that recovery of the SERP costs is reasonable due to restrictions on these employees' basic retirement plan ('BRP'), exclusion of deferred compensation from the BRP calculation, and the need to ensure attraction and retention of qualified employees. Mr. Mashas explained that IRS regulations place limits on pension plan calculations for salaries exceeding \$165,000 and thus salaries in excess of that level are not included in the pension calculation. Mr. Mashas stated that the SERP provides officers with a

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retirement benefit equal to 50 percent of the average of the last three years salary provided that they are at least 60 years old and have at least 20 years of service (Id. at 5-6). In addition, IRS regulations place restrictions on the Company's 401(k) contributions to the extent that 'maximum contribution levels represent a significantly smaller percentage of an officer's salary compared to other employees' (Id. at 4- 5).

RUCO witness Moore proposed a reduction in test year expenses of approximately \$2.7 million associated with the SERP. Mr. Moore stated the cost of these supplemental retirement benefits for select executives is not a necessary cost of providing gas service to customers because the Company's officers are already fairly compensated with a wide array of benefits, including a retirement plan. Mr. Moore cited to the Company's most recent rate case before the Nevada Public Utilities Commission [FN3] where Southwest Gas' SERP expenses were excluded from the Company's operating expenses (RUCO Ex. 5, at 28-29).

We agree with RUCO's position on this issue. Although we rejected RUCO's arguments on this issue in the Company's last rate proceeding, we believe that the record in this case supports a finding that the provision of additional compensation to Southwest Gas' highest paid employees to remedy a perceived deficiency in retirement benefits relative to the Company's other employees is not a reasonable expense that should be recovered in rates. Without the SERP, the Company's officers still enjoy the same retirement benefits available to any other Southwest Gas employee and the attempt to make these executives 'whole' in the sense of allowing a greater percentage of retirement benefits does not meet the test of reasonableness. If the Company wishes to provide additional retirement benefits above the level permitted by IRS regulations applicable to all other employees it may do so at the expense of its shareholders. However, it is not reasonable to place this additional burden on ratepayers.

Miscellaneous Expenses

[18, 19] Through her Direct testimony, Company witness Aldridge indicated that the application included an adjustment to remove certain miscellaneous expenses for items such as gym memberships, donations and meals (Ex. A-29, at 23).

Based on his review of data requests, RUCO witness Moore proposed an additional adjustment to remove from test year expenses 'payments to chambers of commerce, non-profit organizations, donations, club memberships, gifts, awards, extravagant corporate events and for various meals, lodging and refreshments, which are not necessary in the provisioning of gas service' (RUCO Ex. 5, at 25).

In her Rebuttal testimony, Ms. Aldridge stated that RUCO had failed to justify the exclusion of the various miscellaneous expenses identified by Mr. Moore. Ms. Aldridge claimed that the vast majority of the expenditures are reasonable, recurring, and necessary business expenses and should remain in cost of service. However, after additional review, Ms. Aldridge accepted exclusion of a portion of RUCO's proposed disallowance (\$62,165 Arizona jurisdictional), but further

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testified that accepting RUCO's recommendation would result in exclusion of expenses related to moving expenses for a transferred employee; safety awards and costs related to the Company's Operations Center; alcohol and drug testing; and continuing professional education (Ex. A-30, at 15-16).

In his Surrebuttal testimony, Mr. Moore indicated that there were additional expenses the Company had not removed that RUCO believes should not be recoverable through rates. Examples of expenses that Mr. Moore claims remain in the Company's miscellaneous expenses include: liquor, coffee, water, ice, sodas, smoothies, bagels, donuts, subs, trophies, flowers, gift certificates, photographs, charitable/community service club donations, travel reduction programs, shareholder meetings, recognition events, sports events, club memberships, art work, and barbecues and accessories (RUCO Ex. 6, at 20-21). Mr. Moore stated that RUCO would agree to reduce its proposed disallowance by approximately 20 percent, from \$346,299 to \$277,039, 'to avoid the tedious litigation of line-by-line examination of the 40 pages of workpapers' (Id. at 21).

In her Rejoinder testimony, Ms. Aldridge claimed that specific items identified by Mr. Moore (i.e., liquor, club donations, sports events, club memberships, barbecues) were removed by the Company as part of the \$62,165 adjustment described above (Ex. A-31, at 14-15). She indicated that certain meal costs and expenses related to employee appreciation and charitable events were not removed because she believes such expenses are reasonable business expenses. Ms. Aldridge also criticized RUCO's analysis of the workpapers provided through data requests as lacking sufficient detail which was 'not even enough for the Company to determine whether a transaction should remain in cost of service' (emphasis original) (Id. at 16). She therefore concluded that 'RUCO has simply presented insufficient evidence to support their proposed disallowance' (Id.). On cross-examination, Ms. Aldridge maintained that she had removed expenses related to barbecues, Jeep tours, and balloon rides as part of the \$62,165 adjustment, but that other expenses for items such as awards for meter reading accuracy, safe driving awards, shareholder meetings, photographs, sympathy cards and flowers are necessary business expenses that should be recovered through rates (Tr. 353-358, 583-587). She admitted that the exclusion of \$62,165 of expenses (for barbecues, Jeep tours etc.) were removed only after RUCO raised the issue through its testimony (Tr. 583).

Although we appreciate Ms. Aldridge's attempt to exclude expenses that are clearly inappropriate for recovery from ratepayers, we do not believe that the Company has met its burden of proving the reasonableness of all of the miscellaneous expenses for which it seeks recovery. It is curious that Southwest Gas seeks to cast the burden of proving the unreasonableness of expenses on RUCO, especially once RUCO has provided some evidence that certain claimed expenses are inappropriate and which evidence, by the Company's own admission, should result in additional exclusions. Given the state of the record, it is unclear precisely which additional miscellaneous expenses should be excluded from cost of service, but we believe that at least a portion of the items that the Company believes are reasonable business expenses should be disallowed (e.g., shareholder meeting

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expenses). Because the Company failed to sustain its burden of proof on this issue, but also recognizing that many of these miscellaneous expenses may be legitimate and reasonable business expenses, we will disallow half of RUCO's original proposed disallowance (\$346,299 X 50% = \$173,150 disallowance).

Southwest Gas Legal Arguments

[20-22] Throughout its legal Briefs, Southwest Gas repeatedly cites the case of Anaheim, Riverside, Banning, Colton, and Azusa, California v. Federal Energy Regulatory Commission, 669 F.2d 799, 809 (U.S. App. D.C. 1981), to support its assertion that Staff's recommendations must fail because Staff failed to present sufficient evidence to raise a serious doubt as to the prudence of the Company's proposal. As Staff points out in its Reply Brief, the Anaheim case was based on the Federal Power Act which, pursuant to 16 U.S.C. § 824d(e), imposes on the utility company the 'burden of proof to show that the increased rate of charge is just and reasonable.' The Anaheim case, while not controlling precedent, also stands for the proposition that once a party challenges the propriety of a particular aspect of the company's application with some credible evidence, it is incumbent upon the utility to demonstrate the reasonableness of its proposals. The evidence presented through sworn testimony and other exhibits has been carefully weighed and a just and reasonable result achieved based on consideration of the competing evidence and arguments. As established by the Arizona Constitution and relevant case law, this Commission has broad discretion in setting just and reasonable rates and we believe our findings herein achieve that goal despite the Company's disagreement.

Southwest Gas also repeatedly cites West Ohio Gas v. Public Utilities Commission of Ohio, 294 U.S. 63 (1935), to support its contention that specific expense items, including advertising and promotional costs, must be presumed reasonable. While the West Ohio Gas case indicates that 'good faith' should be presumed on the part of a company's managers with respect to the prudence of expenditures, we disagree with the position advocated by Southwest Gas that our consideration of the reasonableness of any particular expense may not include recognition of the relative benefits that may be derived from such costs. The test of reasonableness is based on a host of considerations presented in the record and may not be reduced to a simple pass through of costs claimed by the Company in order to pass legal muster. The Commission's ratemaking authority allows precisely the type of analysis that has been conducted with respect to these expense items and is consistent with case law interpreting that authority. Net Operating Income

[23, 24] Consistent with the foregoing discussion, we will allow adjusted test year operating expenses of \$275,031,605, which based on test year revenues of \$322,865,978, results in test year adjusted operating income of \$47,834,373, a 6.63 percent rate of return on FVRB.

COST OF CAPITAL

As amended at the hearing, Southwest Gas recommends that the Commission determine

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the Company's cost of common equity to be 11.42 percent if its proposed conservation margin tracker ('CMT') is not adopted and 11.17 percent with adoption of the CMT (see discussion of CMT below). The Company's weighted cost of capital recommendation is 9.24 percent without the CMT and 9.13 percent with the CMT (Tr. 783-784; Ex. A-54). Staff recommends a cost of common equity rate of 9.50 percent with an overall weighted average cost of capital determination of 8.40 percent (Ex. S-1, SGH-1, Sched. 11). RUCO proposes adoption of a cost of common equity of 10.15 percent and a weighted average cost of capital of 8.64 percent (RUCO Ex. 1, WAR-1). Capital Structure

[25] During the test year, Southwest Gas had average actual capital structure consisting of 34.5 percent common equity, 5.3 percent preferred stock, and 60.2 percent long-term debt (Ex. A-38, TKW-1). The Company, Staff, and RUCO agree that the Commission should employ a hypothetical capital structure for purposes of setting rates in this proceeding. However, Staff disagrees with the Company and RUCO as to the composition of the hypothetical structure.

Southwest Gas proposes adoption of a hypothetical capital structure of 42 percent common equity, 5 percent preferred equity, and 53 percent long-term debt (Ex. A-38, at 8-33). According to Company witness Theodore Wood, Southwest Gas has improved its actual common equity ratio from 31.1 percent in 1995 to 37.0 percent as of June 30, 2005, despite the financial challenges facing the Company from a combination of rapid customer growth and inability to earn its authorized rate of return (Ex. A-40, at 7). Mr. Wood stated that the Company's requested 42 percent hypothetical structure is consistent with past Commission practice to set the equity ratio above the Company's actual capital structure but below the average of similar risk natural gas distribution companies (Id. at 11). Mr. Wood criticizes Staff's proposed 40 percent capital structure and cites to Southwest Gas' issuance of approximately 15.8 million shares of common stock between 1994 and 2004, netting \$313.7 million in proceeds, as well as the recent \$60 million Equity Shelf Program, as examples of the Company's dedication to improve its equity ratio despite financial hurdles (Id. at 16; Ex. A-39, at 20-21). Mr. Wood was also critical of Staff's recommendation to require a formal recapitalization plan because of the dilution effect on existing shares and the potential negative impact on the Company's stock price. According to Mr. Wood, such a requirement would be detrimental to the integrity of existing capital and could hinder the Company's ability to maximize proceeds from subsequent stock offerings (Id. at 21-22).

Although, as discussed below, RUCO disagrees with Southwest Gas' overall cost of capital recommendation, it agrees with the Company's hypothetical capital structure proposal. RUCO witness William Rigsby stated that he adopted the Company's hypothetical structure in his analysis because Southwest Gas is close to the average debt and equity percentages in his sample group of local distribution companies ('LDCs'). The capital structures for his sample group averaged 51.2 percent long-term debt, 0.3 percent preferred equity, and 48.5 percent common equity (RUCO Ex. 1, at 44-45). Thus, when Southwest Gas' preferred and common equity are combined under RUCO's proposed hypothetical structure, a 47 percent

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total equity ratio is achieved for purposes of analyzing the Company's cost of capital.

Staff recommends that the Commission adopt a 40 percent hypothetical structure, with 5 percent preferred stock and 55 percent debt, for purposes of determining Southwest Gas' overall cost of capital in this proceeding. Staff witness Stephen Hill testified that the equity ratio of Southwest Gas has been consistently low for more than a decade and that ratepayers should not be required to, in effect, subsidize the Company's equity return to the extent requested by Southwest Gas (Ex. S-1, at 20-27). Mr. Hill stated that Staff's recommended 40 percent equity ratio provides an appropriate balance between financial safety and economy for Southwest Gas and is consistent with the hypothetical structure adopted in the Company's last rate case (Id.). Mr. Hill also recommends that the Commission should require Southwest Gas to submit a re-capitalization plan for how the Company can reach an actual 40 percent equity goal prior to its next rate proceeding. Mr. Hill further proposes that if the Company elects not to increase equity capital to at least 40 percent, the Commission should set rates in the next case using the actual capital structure at that time (Id. at 26).

Although it did not present a specific cost of capital recommendation, AUIA criticized Staff's proposal to require Southwest Gas to adopt a recapitalization plan to increase its equity ratio to at least 40 percent by the Company's next rate case. AUIA argues that the cause of the Company's debt-heavy capital structure is its inability to earn its authorized rate of return over a number of years, which it claims is at least as damaging to shareholders as ratepayers. AUIA witness Walter Meek testified that shareholders would support a plan to achieve a 40 percent equity ratio if the Commission would adopt a rate design that would enable Southwest Gas to actually earn its authorized rate of return (AUIA Ex. 2, at 8).

We agree with Staff that use of a 40 percent equity ratio is appropriate in this proceeding. The 40 percent ratio is more than 5 points higher than the ratio in existence at the end of the test year and 3 points higher than the Company's equity at the end of June 2005. This hypothetical capital structure is consistent with our Order in the Company's last rate case (Decision No. 64172, at 17). Although Southwest Gas has made some progress over the past decade to improve its equity position relative to debt, our continuing need to employ an inflated equity ratio for setting rates in case after case highlights the need to encourage even greater efforts to increase the equity ratio. Ultimately, however, the level of equity lies within the control of the Company's management and not with ratepayers who have been asked to shoulder the burden of rates set based on a hypothetical structure that does not actually exist.

As Staff witness Hill pointed out, ratepayers have for many years been burdened with an authorized return set using a hypothetical capital structure far greater than the Company's actual equity ratio. At some point, we must send Southwest Gas a signal that it must improve its capital structure up to the hypothetical level that has been employed for many years or it must live with the results of its

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actual capital structure. Therefore, we believe it is also appropriate to adopt Staff's recommendation to require Southwest to submit a re-capitalization plan explaining how it intends to achieve a 40 percent equity prior to the Company's next rate case. We do not believe it is necessary, at this time, to determine whether failure to reach the 40 percent goal would result in use of the Company's actual capital structure in its next rate case. However, the possibility of such a determination in the next rate case will depend on the Company's efforts to make progress on this issue based on the plan it develops and implements pursuant to this Order.

Cost of Common Equity

[26] Determining a company's cost of common equity for purposes of setting its overall cost of capital requires an estimation that is both art and science. As evidenced by the competing methodologies employed by the three cost of capital witnesses in this case, there is no clear-cut answer as to which formula should be used for reaching the appropriate outcome. Rather, the three expert witnesses, Messrs. Hanley, Hill, and Rigsby, each rely on various analyses for their recommendations.

Southwest Gas

Southwest Gas' expert witness, Frank Hanley, based his common equity cost recommendation of 11.42 percent (or 11.17 percent with the CMT) on the results of his common equity models, namely, the Discounted Cash Flow ('DCF'), Risk Premium Model ('RPM'), Capital Asset Pricing Model ('CAPM'), and Comparable Earnings Model ('CEM'). According to Mr. Hanley, use of these models is consistent with the Efficient Market Hypothesis ('EMH'), which is based on the premise that investors are aware of all relevant publicly available information in making their investment decisions (Ex. A-35, at 20-24). Mr. Hanley stated that, absent evidence to the contrary, it must be assumed that investors are aware of all of the models he used in his analysis and that those investors take the models into account in making their decisions (Id.).

In his analysis, Mr. Hanley developed two proxy groups of comparable gas distribution companies. Based on an historical comparison of financial data for the proxy groups and Southwest Gas, Mr. Hanley found that Southwest Gas has earned returns well below those of the proxy groups (Tr. 680-681). According to Mr. Hanley, during the period of 1997 through 2003, Southwest Gas achieved an average return on actual book common equity of 6.74 percent in Arizona, compared to the 11.62 percent and 12.11 percent average return on equity ('ROE ') realized by the proxy groups (Ex. A-35, FJH-1).

The Company argues that there is an even greater disparity with the proxy group ROEs if Southwest Gas' greater level of business risk is taken into account, as evidenced by the Standard & Poor business profile of 3.0 for Southwest Gas compared to the proxy group average profiles of 1.8 and 2.0 (Ex. A-35, at 13-14, FJH-11). The Company also claims its ROE request is reasonable compared to other

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litigated cases for LDCs across the country the past several years, where the average ROE granted was 10.91 percent, for companies with a common equity ratio of 47.5 percent (Ex. A-36, at 41, FJH-24). The Company argues that these comparisons support the need for a higher ROE because Southwest Gas is more risky, from both a business and financial risk perspective.

Southwest Gas contends that Staff's recommended ROE understates significantly a reasonable return for the Company based on Value Line forecasts for other LDCs. Mr. Hanley cited to a Value Line survey from June 17, 2005, which reported an expected 12.5 percent ROE for such companies relative to a 45.5 percent common equity ratio (Ex. A-37, at 16). Mr. Hanley criticized Staff's reliance on the DCF method for determining ROE based on his claim that the DCF tends to understate the common equity cost rates when market values exceed book values and when such market-based investors' required rates of return are applied to lower book values (Id. at 7).

The Company also cites to the Hope and Bluefield cases [FN4], as well as Article 15, § 3 of the Arizona Constitution and Residential Utility Consumer Office v. Arizona Corporation Com'n, 199 Ariz. 588 (2001), for the proposition that the Commission must consider Southwest Gas' greater risk relative to other LDCs when determining an appropriate common equity cost rate.

RUCO

RUCO contends that its proposed 10.15 percent cost of common equity is appropriate given the Company's actual capital structure, the current environment of relatively low inflation and interest rates, and the Company's relatively higher financial risk compared to other similar LDCs (RUCO Ex. 1, at 43-45). RUCO witness Rigsby employed both a DCF analysis and CAPM to reach his recommendation. His DCF analysis yielded an 8.91 percent COE result, while the CAPM resulted in a range of 8.82 to 10.39 percent (Id. at 27). In reaching his 10.15 recommendation, Mr. Rigsby rounded up (to 10.40) the upper end of his CAPM results, and then reduced that result by 25 basis points to achieve RUCO's proposed 10.15 cost of common equity (Id.).

Mr. Rigsby acknowledged that his proposal is 124 basis points higher than the 8.91 percent DCF result, but contends Southwest Gas' heavily leveraged position and higher level of financial risk compared to his proxy LDCs warrants a recommendation at the higher end of his results. He also states that his recommendation is close to the 10.50 percent return on common equity adopted by the Nevada Public Utilities Commission in Southwest Gas' most recent rate proceeding (Docket No. 04-3011). Mr. Rigsby indicated that his decision to lower the COE recommendation by 25 basis points from the CAPM upper end was based on RUCO's recommendation to adopt a rate design that mitigates income volatility to Southwest Gas by shifting more of the revenue recovery from the Company's commodity charge to its fixed monthly charge, in lieu of adopting the Company's proposed CMT (Id. at 28). On the other end of the spectrum, his recommendation of 124 basis points above the DCF result reflects concern over the Company's

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inability to achieve higher levels of shareholder equity and the Value Line comparison to other proxy LDCs compared to Southwest Gas (Id. at 29).

Staff

In determining Staff's cost of common equity recommendation in this proceeding, Staff witness Stephen Hill conducted a DCF analysis which resulted in a cost of common equity estimate of 9.20 percent. Mr. Hill stated that, in order to support and temper his DCF results, he used three additional econometric models to estimate the cost of equity capital for a group of firms similar in investment risk to Southwest Gas. The three additional methods used by Mr. Hill are: 1) CAPM; 2) the Modified Earnings-Price Ratio ('MEPR'); and 3) the Market-to-Book Ratio ('MTB'). The sample proxy companies used for these models are the same as those employed by Mr. Hill for his DCF analysis (Ex. S-1, at 36-37). Mr. Hill's CAPM analysis resulted in a cost of capital for the proxy companies ranging from 7.71 to 9.38 percent (Id., Sched. 7). For the MEPR model, the cost of equity capital ranged from 8.68 to 8.78 percent (Id., Sched. 9). Finally, Mr. Hill's MTB analysis resulted in cost of equity capital ranging from 8.84 to 9.46 percent (Id., Sched. 10).

Although Mr. Hill relied primarily on the 9.20 percent DCF result for determining his cost of equity recommendation, he also averaged the corroborative results (i.e., CAPM, MEPR, and MTB) which produced a range of 8.41 to 9.21 percent, which he noted is almost entirely below the DCF result. As a result, Mr. Hill concluded that the DCF was a conservative (i.e., high) estimate of the Company's estimated cost of equity capital and therefore the DCF result should be considered to be in the upper range of equity capital cost for Southwest Gas. However, due to his expectation of higher short-term interest rates in the near term, Mr. Hill stated that it was appropriate to set a range so that his DCF result is near the middle of a reasonable range. He therefore determined that the best estimate of the cost of equity capital for a company facing similar risks as that group of gas distribution companies ranges from 9.00 to 9.50 percent (Id. at 37). Because Southwest Gas' capital structure contains less common equity than the proxy group he used to estimate the cost of equity capital, Mr. Hill concluded that the additional risk faced by Southwest Gas warrants an equity return at the high end of his range, or 9.50 percent (Id. at 40).

Conclusion on Cost of Equity

[27-34] We believe that Staff's recommended cost of equity capital in this proceeding achieves an appropriate result that is supported by the evidence in the record. Staff witness Hill's use of the DCF as the primary basis for determining the Company's reasonable estimated cost of equity capital is a methodology that has been used for many years by this Commission, as well as other regulatory commissions across the country.

As Mr. Hill explained in his testimony, both historical and projected growth rates were calculated for his sample group of gas distribution companies. The

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companies in Mr. Hill's proxy group possess similar risk characteristics and, based on a sustainable growth rate supported by data published Value Line and other financial publications, produced a growth rate estimate of 5.12 percent (Ex. S-1, at 29-34). Although Staff's COE recommendation is based primarily on the DCF analysis, as explained above Mr. Hill also conducted a review of other COE formulas, including CAPM, to corroborate the DCF results.

Mr. Hill also testified that the methods utilized by the Company's witness, which depend heavily on beta (a relative risk measure which is designed to measure investor risk), does not provide an accurate portrayal of actual investment risk (Tr. 877). Staff points out that the Company's witness, Mr. Hanley, excluded 8 of 11 indicated DCF return rates from his proxy group based on his opinion that any result under 9.90 percent did not reflect returns being authorized in other jurisdictions. As Mr. Hill pointed out on the witness stand, if those 8 companies were included in Mr. Hanley's DCF calculation, the result would be approximately 9.2 percent, which is almost identical to Staff's DCF calculation (Tr. 876).

After reviewing the various proposals summarized herein, and as further described in the testimony prepared by the parties' expert witnesses, we believe Staff's cost of equity capital recommendation is an appropriate result for determining the Company's overall cost of capital in this proceeding. Staff's DCF calculation of 9.20 percent, with an upward adjustment of 30 basis points to 9.50 percent, gives recognition to the higher risk faced by Southwest Gas.

We are not persuaded by the Company's legal arguments that adoption of Staff's cost of equity recommendation would result in a violation of the Commission's authority under the Arizona Constitution, the case law interpreting that authority, or of the Hope and Bluefield decisions. Article 15, Section 3 of the Arizona Constitution provides in relevant part that the Commission 'shall have full power to, and shall, prescribe just and reasonable classifications to be used and just and reasonable rates and charges to be made and collected, by public service corporations within the State for service rendered therein.' In determining just and reasonable rates, the Commission has broad discretion subject to the obligation to ascertain the fair value of the utility's property, and establishing rates that 'meet the overall operating costs of the utility and produce a reasonable rate of return.' *Scates, et al. v. Arizona Corp. Com'n*, 118 Ariz. 531, 534, 578 P.2d 612 (Ct. App. 1978). Under the Arizona Constitution, a utility company is entitled to a fair rate of return on the fair value of its properties, 'no more and no less.' *Litchfield Park Service Co. v. Arizona Corp. Com'n*, 178 Ariz. 431, 434, 874 P.2d 988 (Ct. App. 1994), citing *Arizona Corp. Com'n v. Citizens Utilities Co.*, 120 Ariz. 184 (Ct. App. 1978). The oft cited Hope and Bluefield cases provide that the return determined by the Commission must be equal to an investment with similar risks made at generally the same time, and should be sufficient under efficient management to enable the Company to maintain its credit standing and raise funds needed for the proper discharge of its duties.

For the reasons described above, we believe that adoption of Staff's recommendation for a 9.50 cost of equity capital, and overall 8.40 percent

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weighted cost of capital comply with these obligations. Staff's expert witness, although primarily relying on the well-established DCF method for calculating his cost of equity capital, also employed two other tests as a check on the reasonableness of his results. He also pointed out that the Company's witness arbitrarily excluded 8 of the 11 companies in his proxy group because they produced DCF results less than 9.90 percent, and thus skewed downward the overall results on his analysis. Moreover, Staff's witness gave recognition to Southwest Gas' highly leveraged capital structure by adding 30 basis points to his DCF results. We therefore believe that adoption of Staff's recommendation results in a just and reasonable return for Southwest Gas based on the record of this proceeding.

We therefore adopt a cost of equity of 9.50 percent, which results in an overall weighted cost of capital of 8.40 percent.

	Percentage	Cost	Avg. Weighted Cost
Common Equity	40.0%	9.50%	3.80%
Preferred Equity	5.00%	8.20%	0.41%
Total Debt	55.0%	7.61%	4.19%
			8.40%

AUTHORIZED INCREASE

Based on our findings herein, we determine that Southwest Gas is entitled to a gross revenue increase of \$49,345,636.

Fair Value Rate Base	\$1,169,584,038
Adjusted Operating Income	47,834,373
Required Rate of Return	6.63%
Required Operating Income	77,508,617
Operating Income Deficiency	29,674,244
Gross Revenue Conversion Factor	1.6629
Gross Revenue Increase	49,345,636

RATE DESIGN ISSUES

Conservation Margin Tracker

[35-38] Southwest Gas has proposed in this proceeding a decoupling mechanism that it calls a Conservation Margin Tracker ('CMT') to address the Company's ongoing inability to achieve its authorized rate of return due, at least in part, to declining per customer usage on its system. The Company has proposed that the CMT

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be imposed only on the residential class (although it does not oppose broader application). Under the CMT, if Southwest Gas does not achieve its authorized 'margin' (i.e., all costs of providing gas less the cost of the gas itself) per customer class, the CMT would track that shortfall and impose a surcharge on customers in that class the following year based on the prior year's revenue shortfall. In effect, the CMT would insulate Southwest Gas from the risk associated with declining gas usage by customers.

The Company claims that the CMT is a reasonable cost recovery mechanism for the following reasons: it would eliminate the Company's financial disincentive associated with promoting Demand Side Management ('DSM') programs; it would not discourage consumers from conserving natural gas because the more a customer conserves the more the customer would save; it would charge customers only the fixed costs of service that the Commission authorized in the rate case; it would protect customers from the Company earning more than its authorized margin per customer during a colder than normal heating season; it would protect the Company from declining residential use per customer; and it would provide the Company with a more consistent revenue stream by reducing its dependency on gas sales to recover the authorized margin per customer, thus having a positive impact on the Company's ratings with credit agencies and reducing borrowing costs needed to fund infrastructure growth (Ex. A-19, at 18- 23; Ex. A-20, at 14-22; Ex. A-21, at 5-9). Southwest Gas contends that it is willing to modify the CMT or accept another type of decoupling mechanism to address the declining usage problems that it claims all parties have acknowledged exist.

Staff opposes adoption of the CMT because customers would be charged more for gas that is not used the preceding year. Staff argues that if natural gas is relatively inelastic, as the Company contends, the potential for ongoing conservation would be mitigated and usage levels will stabilize over time, thus minimizing the declining usage that impacts the Company's revenues. However, if the declining usage trend continues, Staff claims that the CMT would result in customers incurring additional charges if their conservation efforts proved successful, thereby discouraging price signals that could lead to conservation. Staff also opposes the CMT on the basis that it could result in sharp increases for residential customers if the Company fails to recover its authorized margin. Staff argues that implementation of the CMT would provide Southwest Gas a guaranteed rate of return, rather than the opportunity to earn a reasonable return as required by law. Staff asserts that the Company's historical inability to earn its authorized return should be addressed through traditional rate design methodologies, such as gradually moving closer to a more cost-based rate design. Staff points out that the Nevada Commission rejected an almost identical decoupling mechanism proposed by Southwest Gas.

RUCO also opposes the Company's CMT proposal. Although RUCO agrees that the Commission should modify the existing rate design to allow greater recovery of fixed costs, it claims that the CMT is too extreme a remedy for addressing declining usage. RUCO argues that the approved rate design should not provide the Company with a guaranteed recovery of margin, and would allow recovery from

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customers who were not even on the system when the shortfall occurred. RUCO further opposes the CMT on the basis that it would be applicable only to residential customers, and because the CMT would have the effect of requiring customers to pay the authorized margin for therms they do not consume (RUCO Ex. 3, at 29). RUCO argues that although the Company declined to propose a rate design that would recover all of the margin through the basic service charge, because it believes such a rate design would be inconsistent with the principle of gradualism, it has proposed the CMT which would have the same extreme effect on residential customers.

SWEEP/NRDC expressed understanding of the dilemma faced by Southwest Gas with respect to decreasing usage and revenues. However, SWEEP/NRDC opposes adoption of the CMT in this proceeding. Its witness, Jeff Schlegel, stated that a full analysis of the benefits and drawbacks of decoupling mechanisms for LDCs warrant consideration in a broader context (SWEEP/NRDC Ex. 1, at 7-8). SWEEP/NRDC suggests that the issue of financial disincentives should be addressed through the DSM policy process, via comments and/or workshops. SWEEP/NRDC contends that consideration of the decoupling issues should address questions such as who bears the risk of weather variations and variations in economic growth from forecasted levels and overall demographic and energy usage trends (Id.).

AUIA argues that the financial situation faced by Southwest Gas requires adoption of a decoupling mechanism, such as the CMT, or a significant increase in margin recovery through the fixed monthly charge. AUIA contends that the decoupling concept is not radical or drastic, as Staff and RUCO contend, given the adoption of such a mechanism in at least three other states. AUIA cites the testimony of Company witness Steven Fetter, former Chairman of the Michigan Public Service Commission, in support of the CMT. Mr. Fetter indicated that declining margin recovery from volume sales is a national phenomenon and NARUC has passed a resolution urging its members to consider decoupling mechanisms (Ex. A-7, at 6-8).

Conclusion on CMT

Although we recognize that Southwest Gas is facing increased financial pressure due to declining usage on a per customer basis, we do not believe the proposed CMT should be adopted in this proceeding. The Company has suggested that it is open to other decoupling mechanisms as a solution, and we believe that the issue should be fully explored as part of a broader investigation of usage volatility and margin recovery.

There is conflicting evidence in the record as to whether the recent level of declining per customer usage will continue into the foreseeable future, and whether conservation efforts are the direct cause of Southwest Gas' inability to earn its authorized return from such customers. Further, as RUCO points out, the likely effect of adopting the proposed CMT is that residential customers will be required to pay for gas that they have not used in prior years, a phenomenon that could result in disincentives for such customers to undertake conservation efforts. We are also concerned with the dramatic impact that could be experienced

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by customers faced with a surcharge for not using 'enough' gas the prior year. The Company is requesting that customers provide a guaranteed method of recovering authorized revenues, thereby virtually eliminating the Company's attendant risk. Neither the law nor sound public policy requires such a result and we decline to adopt the Company's CMT in this case.

We encourage the parties to this proceeding to seek rate design alternatives that will truly encourage conservation efforts, while at the same time providing benefits to all affected stakeholders. To that end, Southwest Gas should coordinate its efforts to pursue implementation of a decoupling mechanism through discussions with Staff, RUCO, SWEEP/NRDC, and any other interested parties. Such efforts may be pursued through the DSM policy process, as suggested by SWEEP/NRDC, and through a proposal in the Company's next rate case.

Allocation of Margin Among Customer Classes

[39, 40] As a means of allocating margin costs between the various classes of customers it serves, Southwest Gas presented a cost of service study to support its rate design proposal. Company witness Congdon stated that the Company's allocation of margin methodology is based on this cost of service study, and the proposed allocation would move each class' rate of return closer to cost of service (Ex. A-17, at 22-24). The Company argues that its cost of service study was not challenged by any party and, because its proposed allocation is directly based on the cost of service study, the Company's allocation of margin should be adopted.

RUCO and Staff argue that cost of service is merely the starting point for designing appropriate rates. They contend that in addition to affording the Company revenue stability, other factors must also be considered in designing rates, such as affordability, gradualism, sending appropriate price signals, and conservation goals.

We agree with Staff and RUCO that designing rates is not an exact science that may be achieved by the application of a formula tied directly to a cost of service study. Rather, the formulation of just and reasonable rates is accomplished only through consideration of multiple factors that balances the desire of the Company to recover as much of its margin as possible with recognition of the legitimate interests of customers in paying rates that are affordable, as well as advancing societal goals. As discussed below, we have attempted to determine just and reasonable rates based on these competing principles and interests.

Single-Family Residential Gas Service (G-5)

[41] The residential rate class encompasses the vast majority of Southwest Gas customers and, not surprisingly, residential rate design garnered the most discussion and debate. Southwest Gas, Staff, and RUCO each proposed separate residential rate design recommendations.

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Southwest Gas Proposal

Currently, Southwest Gas' single-family residential gas rates include an \$8 basic monthly charge and a two-tier declining block rate of approximately \$0.49 and \$0.40 per therm, respectively. The break point between the first and second blocks is currently at 8 therms of usage in the summer (May-October) and 40 therms in the winter (November-April).

The Company has proposed an increase in the basic monthly charge from \$8 to \$16, and an increase in the first block volumetric charge from \$0.49 to \$0.66 per therm and a reduction in the second block from \$0.40 to \$0.25 per therm [FN5] (Tr. 283-287). Under the Company's proposal, the break point between blocks would remain at 8 therms during the summer months but would be reduced to 30 therms per month in winter months.

Southwest Gas is critical of RUCO's rate design proposal because, in the Company's view, it does not shift enough of the volumetric charges to the fixed monthly charge and, by eliminating the declining block rate structure, it puts the Company at greater risk of not recovering its authorized margin (See, e.g., Ex. A-51). With respect to Staff's recommendation, Southwest Gas concedes that low volume users will experience a significant increase in rates (Tr. 286-287). However, the Company contends that under either Staff's or RUCO's proposals, higher usage residential customers would fare substantially better under Southwest Gas' rate design because its second block rates would be reduced substantially compared to either current rates or the Staff and RUCO rates. Southwest Gas argues that its rate recommendation would be more beneficial to high volume residential customers, regardless of income, as evidenced by a chart in Mr. Congdon's testimony that shows substantial savings under the Company's plan for customers with usage over 100 therms in a given month (Ex. A-18, at 5). Based on its Exhibit A-50, which shows that usage by low income customers tracks closely the usage seen by non-low income customers, the Company argues that high use, low income customers may be affected even more dramatically because of an inability to pay increased costs associated with the higher second block rates under either the Staff or RUCO recommendations.

RUCO's Proposal

RUCO proposes an increase in the basic customer charge from \$8 to \$10.09 per month, and a flat volumetric rate of approximately \$0.49 for all usage. According to RUCO, its rate design proposal gives recognition to the Company's concerns regarding revenue stability (i.e., the Company's inability to recover margin costs due to declining per customer usage) by placing more cost recovery into the basic customer charge [FN6], while also flattening the current two-tier volumetric structure to send appropriate price signals regarding gas consumption. RUCO witness Diaz Cortez indicated that RUCO's rate design proposal would mitigate the Company's risk of not recovering its authorized revenue requirement due to declining usage (RUCO Ex. 4, at 7).

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Staff's Proposal

Based on its revenue requirement recommendation, Staff proposes an increase in the basic monthly charge from \$8 to \$9.70, accompanied by a two-tier commodity rate of approximately \$0.54 for the first 15 therms in the summer and the first 35 therms in the winter, and \$0.50 for usage in the second block. Staff claims that its proposed rate design moves significantly towards cost-based rates and properly balances the Company's revenue stability concerns with the concepts of gradualism, affordability, and conservation. Staff witness Bob Gray conceded that the Company's rate design recommendation provides greater rate stability than either Staff's or RUCO's proposals. He pointed out, however, that by 'front-loading costs in the customer charge and the first usage block,' the Company has offered a design that is inconsistent with Staff's goal of balancing stability with other important factors (Ex. S-15, at 9). Mr. Gray indicated it is 'mathematically impossible for a customer with low usage, paying a much higher customer charge and a much higher first block rate to not see a large rate increase' (Id. at 8).

Conclusion

Although we are cognizant of Southwest Gas' desire to recover as much of its margin as possible through the monthly customer charge, it is simply untenable to saddle a substantial number of the Company's residential customers with rate increases in excess of 100 percent. Under the Company's recommendation, low usage residential customers would incur not only a doubling of their basic monthly charge (from \$8 to \$16 per month), but would pay a substantial commodity charge increase for usage up to 30 therms per month in the winter (from \$0.49 to \$0.66 per therm). While high usage customers may realize lesser overall increases under the Company's plan, relative to the Staff and RUCO proposals, the Southwest Gas rate design would have the effect of encouraging greater usage of natural gas at a time when, by all accounts, an increase in demand for natural gas is coupled with shortages in supply. We do not believe that it is appropriate to send a signal to customers of 'the more you use, the more you save.'

We are also aware that customers will likely face additional cost increases associated with the Company's purchased gas adjustor ('PGA'). Southwest Gas expected to reach its ten cent PGA cap in January 2006, thus increasing customer bills associated with the cost of gas for a customer using 105 therms a month by approximately \$10.50 per month, regardless of the rate design adopted in this proceeding (Tr. 297-298). The Company will also likely in the near future seek Commission approval for imposition of a surcharge to recover its \$30 million bank balance, adding an additional \$0.055 per therm (i.e., an additional \$5.50 per month for the same customer using 105 therms per month). Although the cost of gas may be largely beyond the Company's control, this additional rate impact must be considered as part of the overall rate impact on customers.

We agree with all parties that movement closer to cost-based rates is in principle a laudable goal. However, that goal must be balanced with consideration of the principles of gradualism, fairness, and encouragement of conservation.

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Based on consideration of competing interests and concerns, we agree that Staff's rate design recommendation appropriately makes significant movement towards cost based rates while providing a measure of protection for customers who will incur substantial rate increases as a result of this base rate case increase. Accordingly, we will adopt Staff's recommended basic monthly charge of \$9.70 and, as adjusted for the revenue requirement adopted herein, a two-tier commodity rate of \$0.54200 for the first 15 therms in the summer and the first 35 therms in the winter, and \$0.50100 for usage in the second block.

Based on the G-5 residential rate design adopted in this case, and assuming an average monthly usage of 29 therms, single-family residential customers would experience an increase under summer rates of 8.9 percent, from \$38.96 to \$42.42 per month, and an increase under winter rates of 8.3 percent, from \$39.71 to \$42.99 [FN7] .

Multi-Family Residential Gas Service (G-6)

[42] Southwest Gas proposes creation of a new multi-family residential rate schedule (G-6) that would, under the Company's revenue requirement recommendation, grant customers in multi-family residences a \$1 per month reduction to the basic monthly charge compared to single-family residence customers (See, Ex. A-2, Sched. H-3). Mr. Congdon stated that creating this separate rate schedule for multi-family residence customers would allow the Commission to moderate the effect on the Company's smallest residential customer class as residential service rates are moved gradually towards cost of service (Ex. A-17, at 26-27). RUCO does not oppose this recommendation.

Staff witness Gray testified, however, that although Staff is not strongly opposed to creation of a multi-family residential rate class, Staff does not believe it is advisable to create a separate rate structure for a small segment of the general rate class. Mr. Gray stated that while there are likely other segments of the residential class that have different characteristics, 'a Balkanization of the residential rate class absent a compelling need to do so is not something Staff will support' (Ex. S-15, at 10).

We agree with Southwest Gas that customers in multi-family dwellings deserve a separate rate categorization to reflect their lower usage characteristics and relatively lower cost to serve as a class. Therefore, we will approve creation of a separate rate schedule for this residential customer class and, consistent with the Company's proposal, impose a basic monthly service charge of \$8.70, plus the commodity charges applicable to Schedule G-5 customers.

Based on the rate design adopted in this case, and assuming an average monthly usage of 29 therms, customers in the new multi-family residential class would experience an increase under summer rates of 5.5 percent, from \$38.96 to \$41.09 per month, and an increase under winter rates of 8.3 percent, from \$39.71 to \$41.54 [FN8] .

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Low-Income Residential Gas Service (G-10)

[43] Southwest Gas proposed elimination of its low-income residential gas service tariff (G-10), with such customers being incorporated into the other residential classes (G-5 and G-6), and the current volumetric discount would be extended to the entire year rather than the current applicability to only winter months (Ex. A-17, at 27-29). However, the Company's proposal would lessen the amount of the discount applicable to low-income customers based on its assertion that there would be less of a need to shield such customers from high winter bills because the Company's rate design proposal, if adopted, would shift a portion of the margin recovery from the winter season to the summer season. Under the Southwest Gas recommendation, the existing \$7.00 per month basic customer charge would be retained for low-income customers, and the current 20 percent discount on the first 150 therms of usage during winter months would be replaced with a year-round 15 percent discount with no usage limit. RUCO does not oppose the proposal and the Company indicates that it has not received any opposition to the proposal from local community action advocates after explaining the plan to those representatives (Id. at 28-29). Mr. Congdon testified that, if the Commission does not accept the Company's rate design proposal, the current 20 percent low-income discount should not be modified (Id.).

Staff opposes the Company's proposal to eliminate Schedule G-10 and modify the low-income residential rate as described above. Staff witness Gray stated that Arizona utilities that offer such a discount typically have a separate, stand-alone tariff and Staff believes maintaining the existing tariff allows a higher profile for the tariff and advances ease of understanding. Mr. Gray agreed with the Company that the \$7.00 customer charge for Schedule G-10 should be maintained at that level, and further indicated that the existing 20 percent discount for the first 150 therms of usage during winter months should be maintained because bills incurred for high winter usage is the critical element for low-income customers (Ex. S-15, at 36-38).

Given our adoption of Staff's residential rate design proposal, it appears Southwest Gas does not advocate adoption of its proposed modification of the low-income tariff. We agree with Staff's recommendation that the current Schedule G-10 should be maintained at its current level and we therefore adopt Staff's proposal to maintain the \$7.00 customer charge and apply a 20 percent discount to the first 150 therms of consumption during winter months.

Special Residential Gas Service for Air Conditioning (G-15)

[44] Southwest Gas recommended that its special residential service tariff for gas air conditioning (G-15) should be eliminated and the small number of customers covered under the tariff folded into the general residential tariff (G-5). Company witness Congdon explained that there is currently only a small difference in the second block rate between the two schedules and the Company's proposal would eliminate the need to administer a separate schedule for this small number of customers. Mr. Congdon added, however, that if the Commission adopts the rate

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designs proposed by either Staff or RUCO, the G-15 schedule should remain intact and the summer air conditioning margin rate should be set at \$0.25 per therm (Ex. A-17, at 29).

Staff witness Gray opposes elimination of the G-15 tariff because typical usage by customers under this schedule is significantly higher than general residential usage. Given this usage pattern differential, Mr. Gray indicated that it is reasonable to continue the separate tariff. Staff recommends that the G-15 tariff should continue to reflect the G-5 tariff rates, with the exception that the G-15 second summer usage block should be increased from approximately \$0.19125 to \$0.28200 per therm (Ex. S-15, at 41-42; Ex. S-16).

Given our adoption of Staff's residential rate design proposal, it appears Southwest Gas does not advocate adoption of its proposed modification of the residential air conditioning tariff. We agree with Staff's recommendation that the current Schedule G-15 should be maintained at its current level, with the exception of an increase to the summer second block.

Master Metered Mobile Home Park Gas Service (G-20)

[45] In its application, Southwest Gas proposed increasing the basic monthly charge for master metered mobile home park service customers from \$50 to \$100, and increasing the commodity charge from approximately \$0.314 to approximately \$0.323 per therm (Ex. A-1, Sched. H-3). The Company did not present testimony on this issue, but argues that its recommendation better reflects its cost of service for this customer class, compared to Staff's proposal (Id., Sched. H-6).

Staff witness Gray stated that Staff's recommendation is to increase the basic monthly charge from \$50 to \$60, and to increase the volumetric charge from \$0.31415 to \$0.38400 per therm (Ex. S-16).

Consistent with principles of gradualism and fairness, we will adopt Staff's recommendation on this issue so as not to impose such an abrupt and significant rate increase on customers taking service under this tariff.

General Gas Service (G-25)

With respect to the Company's recommendations regarding this rate schedule, which includes various sizes of commercial customers, the following issues are addressed below: moving current Armed Forces customers on Schedule G-35 into Schedule G-25; appropriateness of creating a new sub-class for small use customers in the class and relative basic customer charge increase recommendations for different size customers within the class; and use of coincident peak or non-coincident peak for determining the demand charge for large G-25 customers.

Elimination of Armed Forces Rate Schedule (G-35)

[46] In its application, Southwest Gas recommended elimination of Armed Forces

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Rate Schedule G-35, and movement of existing customers under that schedule into the large general gas service rate under Schedule G-25. The basis of the Company's proposal is that if G-35 customers were permitted to choose to take service under either G-25 or G-35, the Company would experience a shortfall in margins.

DOD witness Dan Neidlinger filed testimony supporting Southwest Gas' recommendation, stating that DOD customers should logically be classified with other large gas users for ratemaking purposes. Mr. Neidlinger's testimony indicates that if the overall revenue requirements are established near the levels recommended by Staff or RUCO, DOD recommends adoption of RUCO's proposed G-25 rates (DOD Ex. 1, at 2-3).

Although Staff initially suggested that Schedule G-35 should be maintained and customers should be able to choose between G-25 or G-35 (Ex. S-15, at 43-47), Mr. Gray subsequently withdrew Staff's opposition based on DOD's agreement with the Company's proposal (Tr. 1097-1098).

Given Staff's acquiescence on this issue, we will adopt the Company's proposal to eliminate Rate Schedule G-35 for Armed Services customers and to include those customers under the large general gas service tariff, Schedule G-25.

New Sub-Class for Small Use Customers and Basic Service Charge Recommendations

[47] Southwest Gas' Schedule G-25 currently includes discrete prices for small (annual 0-7,200 therms), medium (annual 7,201-180,000 therms), and large (annual usage greater than 180,000 therms). The Company proposed the creation of a new sub-class within the small customer category, so that commercial customers with very low usage (i.e., less than 600 therms annually) would be separated for rate design purposes from other small group customers that use between 601 and 7,200 therms annually (Ex. A-16, at 17-18). Mr. Congdon testified that the Company's proposal would allow pricing that more closely matches its cost of service while also mitigating the impact of the rate increase on the smallest customers within the class. He claimed that the Company's proposed tariff adjustments were made to minimize the differences in monthly bills at the cross-over volumes between general service rate schedules (Id. at 19).

RUCO does not oppose creation of this sub-class category, but Staff contends that the members of the new sub-class 'would see a much larger rate increase than if they had remained part of the current small commercial class presently in existence' (Ex. S-15, at 43). Therefore, Staff witness Gray recommends retaining the current usage levels for small, medium and large G-25 customers (Id. at 44).

The proposals for customers within the G-25 rate schedule, including the Company's claimed cost of serving the customer classes (Ex. A-1, Sched H-6), are as follows (Ex. A-17, at 30-32):

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Proposed Schedule	Current	Staff	RUCO	SWG	Cost of Serv.
Small GS	\$20.00	\$24.00	\$34.57	\$25.00	\$74.86
Medium GS	20.00	24.00	48.39	35.00	79.02
Large GS	90.00	105.00	207.00	150.00	145.81
Transport Elig.	500.00	540.00	1,037.00	750.00	754.99

Based on our review of the record, we find the Company's recommendation to create a separate sub-class of very small customers is reasonable and should be adopted. However, in order to mitigate the severity of the customer charge increases on customers in this class, we will adopt a modified increase in the customer charges as follows: customers in the new small use segment -- \$25.00; customers in the medium class -- \$33.00; customers in the large class -- \$145.00; and customers in the transportation eligible class -- \$720.00. We believe these approved customer charges move the customers in this rate schedule closer to the Company's cost of service while, at the same time, protecting customers from dramatic increases in rates.

Demand Charge Determination

[48] Southwest Gas also proposed to change its method of measuring a large customer's peak demand from a coincident peak method (i.e., system peak month) to a non-coincident peak method (i.e., customer peak month). The Company claims that its non-coincident peak measurement would take some of the risk of revenue recovery out of rates while, at the same time, reflecting value to customers on an annual basis (Ex. A-17, at 33).

Staff opposes changing the demand charge calculation formula from use of coincident peak due to the potential that 'some customers may have structured their consumption and operations such that they reduce consumption on what is likely to be [the Company's] peak month' and, therefore, the change could have a significant rate impact on customers who have very different coincident and non-coincident peaks (Ex. S-15, at 44).

DOD agreed with the Company's recommendation, in part. DOD witness Neidlinger stated support for a modified non-coincident peak method 'whereby a customer's billing demand would be based on the highest monthly demand experienced during any winter month' (DOD Ex. 1, at 3). DOD would exclude from the calculation demands during the summer months of May through September.

Although we believe DOD's proposed modification of the non-coincident peak method for determining the demand charge has merit, there is not sufficient data in the record to support its adoption. We will therefore adopt the Company's non-coincident peak measurement recommendation as a means of taking some of the risk of revenue recovery out of rates while, at the same time, reflecting value to customers on an annual basis.

Air Conditioning Gas Service (G-40)

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Southwest Gas proposed the imposition of a single basic service charge of \$25 for customers taking service under this tariff, rather than the Company's otherwise applicable basic service charge (Ex. A-16, at 14). However, the Company offered no testimony explaining the need for a distinct basic service charge for this tariff.

Staff witness Gray stated that the Company has a number of tariffs where the basic service charge is set by what it would be on the customer's otherwise applicable tariff, and this is the only tariff where Southwest Gas is proposing such a change (Ex. S-15, at 48).

We agree with Staff that there does not appear to be any reasonable justification for why the current tariff should be changed and it is more reasonable to have a larger basic service charge for a large commercial customer under the tariff compared to a small commercial customer taking service under the tariff (Id.). We therefore adopt Staff's recommendation on this issue.

Gas Service for Compression on Customer's Premises (G-55)

[49] Southwest Gas proposes increasing the basic monthly charge for customers taking service under Schedule G-55, gas service for compression on customer premises, from \$8.00 to \$12.00 for residential customers; from \$20.00 to \$25.00 for small customers; and from \$170.00 to \$350.00 for large customers. The Company also proposes increasing the commodity charge from \$0.13305 to \$0.13669 per therm for all customers served under the G-55 tariff (Ex. A-1, Sched. H-3). Although Southwest Gas offered no specific testimony explaining the level of proposed increases, the Company claims that its proposal for increasing rates under the tariff reflect the Company's cost to serve this class of customers.

Staff witness Gray filed testimony recommending lesser rate increases. Mr. Gray recommended increasing the basic monthly charge for residential customers under this tariff from \$8.00 to \$9.70; small customers from \$20.00 to \$24.00; and large customers from \$170.00 to \$190.00 (Ex. S-13, at 49; Ex. S-16). He also proposed increasing the commodity charge from the current \$0.13305 to \$0.17000 per therm (Id.).

Consistent with principles of gradualism and fairness, we will adopt Staff's recommendation on this issue so as not to impose such an abrupt and significant rate increase on customers taking service under this tariff. However, since the small customer service charge is tied to Schedule G-25 (i.e., \$25.00), the customer charge for such customers shall be set accordingly.

Cogeneration Gas Service (G-60)

[50] Southwest Gas proposes that its cogeneration gas service tariff (G-60) be made available to all electric generation customers, with the exception that customers whose facilities exceed 5 megawatts ('MW') would be required to take transportation service at the Schedule G-60 rates. Company witness Congdon stated that this exclusion is necessary to eliminate 'the risk to Southwest Gas' sales

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customers associated with the procurement of the upstream gas supply and interstate pipeline requirements for these large customers' (Ex. A-17, at 35-36).

Staff witness Gray testified that, although the Company expressed legitimate concerns regarding the possibility of significant new electric generation loads straining its system, Staff recommends that Southwest Gas should develop provisions of the G-60 tariff that would provide sufficient protections for the system and other core customers (Ex. S-13, at 50-51). Mr. Gray indicated that, in his opinion, it would be unfair to impose a provision that has the effect of potentially barring certain customers from taking service under this tariff due to the customer's size (Id.). Staff therefore proposes that the otherwise applicable general service and essential agricultural basic service charges should continue to be applied to G-60 customers, and that the per therm rate should be increased from \$0.08934 to \$0.11400 (Id. at 51; Ex. S-16).

We agree with Staff's recommendation regarding the Schedule G-60 tariff. We see no valid reason for restricting the Schedule G-60 tariff in the manner suggested by Southwest Gas. However, to the extent Southwest Gas believes additional protection for its system and core sales customers is necessary, the Company may separately propose in a tariff amendment filing, language that it believes would provide necessary safeguards.

Small Essential Agricultural User Gas Service (G-75)

[51] Southwest Gas proposed increasing the basic monthly charge for customers taking service under the small essential agricultural user gas service tariff (G-75) from the current \$75 per month to \$150 per month, and increasing the Schedule G-75 commodity charge from \$0.19468 to \$0.22186 per therm (Ex. A-1, Sched. H-3). The Company also recommends freezing Schedule G-75 so no new customers could take service under the tariff and would instead be required to be served under the general service tariff, Schedule G-25. Currently, customers may choose to be served under either Schedule G-75 or the general service tariff, G-25. According to Southwest Gas, its request to reclassify customers on the G-75 tariff is consistent with Decision No. 58377 (August 12, 1993) in which, according to the Company, the Commission suggested that customers under this schedule be moved to the general service tariff 'and to gradually eliminate Schedule G-75' [FN9] (Southwest Gas Initial Brief at 60).

Staff witness Gray testified that Staff opposes closing Schedule G-75 because elimination of the tariff would remove the option that currently exists for eligible agricultural customers to choose between general service and the G-75 tariff. Mr. Gray stated that 'absent a powerful reason to take this service option away' the G-75 tariff should be retained (Ex. S-13, at 52). In his surrebuttal testimony, Mr. Gray indicated his belief that the Company has not presented a compelling reason why eligible new customers should be precluded from exercising the same option that currently exists (Ex. S-15, at 12). With respect to the applicable charges, Mr. Gray recommended that the basic service charge should be increased from \$75.00 to \$90.00, and the per therm rate should be increased from

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\$0.19468 to \$0.22300 (Ex. S-13, at 52; Ex. S-16).

Consistent with principles of gradualism and fairness, we will adopt Staff's recommendation on this issue so as not to impose such an abrupt and significant rate increase on customers taking service under this tariff. We agree with the principles stated in Decision No. 58377, that charges for this agricultural tariff should continue to move gradually closer to cost of service and the general service rate. However, we do not believe the Company's proposal to double the basic monthly charge for such customers, and to freeze new customers from taking service under the G-75 tariff, is consistent with the goals set forth in that prior Decision or with principles of fundamental fairness.

Natural Gas Engine Gas Service (G-80)

[52, 53] As described by Company witness Congdon, customers served under the natural gas engine gas service tariff (G-80), use natural gas engines to pump water for agricultural irrigation (Ex. A-17, at 36-38). Mr. Congdon stated that the G-80 tariff serves customers in a very price sensitive market in which the customers may decide, based on the cost of gas service, to either switch to electricity to operate their pumps or simply not to irrigate and produce crops at all (Id.). In its application, Southwest Gas proposes to increase the basic monthly charge in the peak season (April-September) from \$80 to \$100, but reduce the commodity margin from the current rate of \$0.16189 to \$0.15848 per therm (Ex. A-1, Sched. H-3). No customer charge applies during off-peak months (Id.). In support of its proposal, Mr. Congdon stated that it did not assign an increase in margin to this class of customers because the Company is concerned that it may lose some of the G-80 tariff customers due solely to increases in the price of gas, which gas cost is reset for this class semi-annually, on April 1st and October 1st (Ex. A-17, at 37). Due to these competitive concerns, Southwest Gas opposes Staff's recommendation to increase the margin recovery associated with the G-80 tariff class (Id.).

Staff witness Gray agrees that the off-peak basic service charge should remain at zero. However, he recommends that the on-peak customer charge should be increased from \$80 to \$95 per month, and the per therm rate should be increased from \$0.16189 to \$0.17700 (Ex. S-13, at 53; Ex. S-16). In his surrebuttal testimony, Mr. Gray stated that Staff took into account the Company's competitive concerns concerning the G-80 rate class, but 'Staff does not believe the potential for customers leaving a given rate class should totally exempt that rate class from bearing some, albeit small, portion of the overall rate increase' (Ex. S-15, at 12-13). He pointed out that, under Staff's recommendation, the Schedule G-80 customers would receive the smallest revenue increase (approximately 2.77 percent under Staff's revenue requirement proposal) of any rate class under Staff's recommended rate design (Id.).

We agree with Staff that the relatively small margin increase assigned to the G-80 tariff class is a reasonable outcome based on the competing concerns of all customers affected by this proceeding. Although we recognize that retention of

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customers on Southwest Gas' system may provide benefits to all customers, we are not inclined to broker prices between competing sources of energy by limiting increases that may otherwise be applicable to a given class of customers based on cost of service principles and other factors that are weighed in determining rates for all classes of customers. We will therefore adopt Staff's recommendation on this issue.

MISCELLANEOUS ISSUES

Billing Determinants

[54] Billing determinants are established by developing an annualized number of bills and volumes for the test period under the Company's current rate schedules (Ex. A-16, at 3). Accurate billing determinants are important because if too few determinants are used, tariff prices would be set unnecessarily high and, likewise, too many billing determinants would result in tariff prices that are too low to capture the established revenue requirement (Tr. 241-244).

Company witness Congdon testified that the proposed billing determinants were compiled by taking the monthly recorded number of bills and therms, by rate schedule, for the 12-month test year period, with the following adjustments to the recorded bills and therms: (1) billing adjustments (to remove anomalies); (2) volume annualizations (customer specific adjustments to reflect a full year's consumption for each customer, excluding the residential and small commercial classes); (3) customer reclassifications (to move customers and volumes between tariff schedules to reflect end of test year composition); (4) weather normalization (to accurately depict monthly volumes under normal weather conditions); (5) customer annualizations (for residential and small commercial classes, captures seasonal nature of test year customer growth); and (6) reclassification of full margin transportation customers to present rate schedules (to reflect pricing at present rate schedules) (Ex. A-16, at 3- 8).

Although Staff does not oppose the Company's proposed billing determinants [FN10], RUCO witness Moore filed testimony reflecting modifications that RUCO believes are necessary to obtain accurate determinants. Mr. Moore initially revised the billing determinants to reflect updated bill frequency analyses, and imputed revised billing determinants into the Company's proposed rate design, and, finally, annualized the imputed billing determinants using the Company's pro forma adjustments (RUCO Ex. 5, at 5).

In his Rebuttal testimony, Mr. Congdon identified several errors he believes were made in RUCO's calculation. He stated that RUCO improperly attempted to utilize the Company's actual recorded bills and failed to utilize the residential bill frequency analyses ('BFAs') which are necessary to correctly price the first and second block volumes of the existing rates. Mr. Congdon indicated that RUCO's analysis understated first block revenues by approximately 88 million therms, which resulted in those therms being priced at the lower second block rate, thereby understating residential revenues by \$7.4 million (Ex. A-17, at 24-25).

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Mr. Congdon also claimed that RUCO improperly used ratios to distribute the Company's total proposed adjustments to bills and volumes.

In his Surrebuttal testimony, Mr. Moore stated that following review of a data request response and several telephone conversations with Southwest Gas, the Company was unable to provide a set of test year billing determinants that generate its test year recorded revenues. Mr. Moore claims that RUCO analyzed the BFAs provided by the Company and determined a set of determinants that accurately reflect the size of the test year customer base, its usage patterns, and that generate the test year recorded revenue. RUCO then added pro forma adjustments to create a normalized set of test year determinants to design a rate structure that would produce RUCO's recommended revenue requirement (RUCO Ex. 6, at 4-7). RUCO argues that it corrected whatever errors existed in its initial calculation through its surrebuttal testimony and that the workpapers for those calculations were provided to the Company. RUCO claims that there is no assurance that the Company's proposal is any more accurate than RUCO's revised calculations.

The Company provided a response to a RUCO data request to clarify the alleged errors, but Mr. Congdon claimed in his Rejoinder testimony that RUCO's continued insistence on adjustments to bills and volumes reflected several computational errors including: improper calculation of the Company's average test year cost of gas; incorrect pricing of bills and volumes for the Company's former Black Mountain Gas Company customers; and improperly pricing the gas cost and basic service charge revenue applicable to Schedule G-60 and G-80 (Ex. A-18, at 9-13). Despite attempting to reconcile RUCO's adjustments through data requests and telephone conversations, Mr. Congdon believed that RUCO's proposal continued to understate residential gas cost by \$6 million, and overstated residential margin by the same amount (Id. at 12). On cross-examination, Mr. Congdon testified that the billing determinants proposal in RUCO's Surrebuttal testimony was closer than its original calculation, but RUCO's number of bills was still approximately 22,000 higher than the Company's calculation and RUCO's volumes were overstated by approximately 5 million therms (Tr. 244).

It is fairly clear that Southwest Gas and RUCO never achieved a meeting of the minds regarding the appropriate billing determinant methodology. There is little doubt that RUCO's initial calculations were flawed and, although subsequent amendments were made to its proposal, for the reasons identified by Mr. Congdon we believe that the billing determinant recommendation presented by Southwest Gas is the most reliable proposal and should be adopted in this proceeding (subject to the Staff modifications discussed above). In future cases, the parties would be wise to initiate discovery regarding complex issues such as this at an early stage in order to avoid the necessity of amendments to their recommendations at a later stage in the process.

Purchased Gas Adjustor

[55, 56] All of Southwest Gas' core customers are served under a purchased gas adjustor ('PGA') mechanism [FN11]. The PGA mechanism uses a 12-month rolling

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average, whereby a new PGA rate is calculated each month. Each month the Company calculates its average cost of natural gas, on a per therm basis, for the most recent 12 months. The monthly PGA rate is then determined by subtracting the base cost of gas [FN12] from the 12-month average cost of gas. As explained by Staff witness Gray, the PGA rate is 'banded,' which means each month when the PGA rate is set it cannot be set at a rate that is more than \$0.10 per therm different than the rate that was in place in any of the previous 12 months (Ex. S-13, at 8). The PGA currently has a \$22.4 million bank balance 'trigger,' such that if the balance becomes over-collected by \$22.4 million or more, the Company is required to take certain actions to address the under-collected balance (Id. at 18).

Staff made several recommendations regarding the PGA mechanism. Staff proposed that the base cost of gas should be set at zero and the full commodity cost of gas incorporated into the PGA. Staff also recommended that the current \$22.4 million bank balance trigger should be increased to \$29.2 million and an officer of Southwest Gas should be required certify each PGA report. Each of these issues is discussed below. Staff further recommended that the bank balance interest rate should be set based on the one-year nominal Treasury constant maturities rate, and that the PGA report should identify certain additional details regarding purchases and usage [FN13]. These issues are not in dispute and are not addressed further. The reporting details recommended by Staff are in addition to all current reporting requirements. Further, the Company's PGA monthly reports to the Commission should continue to comply with all current reporting requirements and include the beginning bank balance, any offsets, and the ending bank balance.

Setting Base Cost of Gas at Zero

The base cost of gas is currently included along with the margin within the tariffed rate per therm for each rate class, with the monthly PGA listed as a separate line item on customer bills. Mr. Gray explained that in a rate case the Commission traditionally addresses all costs aside from the cost of gas component, which is treated separately through the PGA function. Because the margin rate recovers all of the other costs, such as metering, billing, customer service, personnel, and facility costs, the rates established in a proceeding such as this affect only the margin rate component, consisting of the tariffed rates and the basic service charge. As a result, the margin rate change for a given customer class is always much higher than the percentage increase on customer bills, given the treatment of the cost of gas component as a constant in the rate proceeding. Mr. Gray pointed out that including both a margin component and a base cost of gas in the tariffed (commodity) rate can result in significant confusion for customers who are trying to understand their bills, especially after rate increases are granted (Ex. S-13, at 8-16).

Southwest Gas' current base cost of gas is \$0.37034 per therm, as established in the Company's last rate case (Decision No. 64172). In its application, Southwest Gas proposed increasing the base cost of gas to \$0.53436 per therm, which Staff found to be reasonable. However, Staff witness Gray recommended, as an alternative, that the base cost of gas be set at zero as a means of minimizing

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customer confusion. Under Mr. Gray's recommendation, setting the base cost of gas at zero would effectively eliminate the base cost of gas component so that the PGA rate would include the previously separate base cost of gas amount. Thus, a single line item on customer bills would include the full commodity cost (absent a temporary surcharge or credit), allowing customers to easily see the changing cost of gas component separate from the margin component (Ex. S-13, at 13).

In order to alleviate short-term customer confusion from such a change, Staff further recommends that Southwest Gas should create specific customer education materials to explain the change (including, e.g., a side-by-side bill comparison under the old and new rate structures) (Id. at 14-15). Mr. Gray also points out that setting the base cost of gas at zero would cause the monthly PGA rate component to significantly increase, and well beyond what a typical application of the \$0.10 therm band would enable the monthly PGA rate to reflect. To remedy this problem, Staff recommends that, when applying the \$0.10 per therm band for the first 12 months after this Decision, Southwest Gas should compare the new monthly PGA rate to the sum of the base cost of gas and the monthly PGA in prior months. Taking this approach would, according to Mr. Gray, provide a consistent benchmark for applying the \$0.10 per therm band while transitioning to a base cost of gas of zero (Id. at 15-16).

Southwest Gas indicated that it does not oppose Staff's recommendation to set the base cost of gas to zero (Id. at 14; Tr. 270). Mr. Congdon also testified at the hearing that the Company does not oppose Staff's recommendation to create specific customer education materials, 'like a bill stuffer' that would go out in customer bills to explain the change (Tr. 270).

We believe Staff's recommendation to set the base cost of gas at zero is appropriate and, once fully implemented, should enhance customer understanding of their bills. This proposal will allow customers to more easily track the separate components that go into the provision of gas service, especially the gas component during periods of volatility. We appreciate Staff's effort in devising this recommendation, as well as the Company's agreement with a proposal that should minimize customer confusion, while at the same time allowing the Company to recover its costs. As a final matter on this issue, we direct the Company to submit to Staff for its review a copy of all customer education materials related to this issue prior to the materials being distributed to customers.

PGA Mechanism Trigger Level

[57] Southwest Gas' current PGA mechanism was implemented in June 1999, at a time when natural gas prices had remained relatively stable for a number of years. Staff witness Gray testified that, although no PGA structure can change or mitigate the fact that natural gas prices have increased dramatically in recent years, Staff believes the current PGA mechanism reasonably balances the protection of customers from wildly fluctuating gas prices with the goal of sending, to a certain extent, price signals to customers regarding gas prices (Ex. S-13, at 17). Therefore, Staff recommends that the existing PGA mechanism should be retained,

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subject to the limited modifications discussed below.

Mr. Gray explained that when the rolling average PGA mechanism was established by Decision No. 61225 (October 30, 1998), the \$22.4 million trigger level was set on the basis of consumption levels for Southwest Gas in 1996 and 1997 (approximately 447 million therms annually). For 2003 and 2004, the Company had an average annual consumption of 516 million therms (Id. at 18). Mr. Gray stated that although there is not necessarily one right trigger level, given the increasing annual cost of gas (among other relevant considerations regarding the impact on customers and the Company), Staff believes the trigger level for the PGA bank balance should be increased from \$22.4 million to \$29.2 million. According to Staff, the proposed trigger level increase should provide a level of flexibility to absorb higher usage and higher natural gas costs in the PGA bank balance, while also providing a measure of protection for customers and the Company if a positive or negative balance were to be carried within the balance for a period of time (Id. at 19-21).

Company witness Gieseke testified that while Southwest Gas is not necessarily opposed to an increase in the PGA bank balance trigger level, to the extent such an increase were to be adopted the Company believes the current \$0.10 per therm PGA adjustment rate band should also be increased to \$0.20 per therm [FN14] (Ex. A-21, at 10-11). Company witness Congdon stated that an increase in the bank balance trigger level would potentially increase the amount of money carried in the balancing account, thereby increasing the Company's business risk in the eyes of the financial community (Ex. A-17, at 40). Southwest argues that an increase in the adjustment cap would save customers in the long-term by minimizing deferrals to the balancing account, thereby reducing carrying costs on the PGA balance, and resulting in less cost to customers in a future period (Id.). Southwest Gas also contends that leaving the current \$0.10 band in place would hinder the adjustment of gas rates that are used to reflect the 12-month average cost and would distort the true marginal cost of natural gas, thus failing to send appropriate price signals to customers (Ex. A-21, at 10-11).

We agree with Staff that the PGA bank balance trigger level should be increased to \$29.2 million for the reasons set forth in Staff witness Gray's testimony. As stated above, the Company is not opposed to the trigger level increase as long as the change is accompanied by a corresponding increase in the \$0.10 per therm adjustment band. We believe that an increase in the trigger amount is a reasonable adjustment based on various factors, including the significant increase in gas consumption levels since the trigger was originally established.

Given the current volatility in the price of gas we believe a slight adjustment of the current adjustment band is appropriate. According to Mr. Gray, the purpose of the band is to limit the amount by which the monthly PGA rate could adjust automatically within a 12 month period, without further action by the Commission (Ex. A-15, at 5-6). Staff does not oppose an increase of the band in principle, but does not believe there is a need to link what it considers a moderate trigger level increase with an expansion of the adjustment band, as proposed by the Company (Id.). Although the trigger level and the adjustment band are not

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inextricably intertwined, limiting the band to its current level could result in greater long-term costs for the Company's customers. Mr. Gieseke testified that the Company's rolling 12-month average cost was expected to exceed the \$0.10 upper band by January 2006, an indication that an increase in the band is warranted at this time. As Mr. Gray stated in his Rebuttal testimony, the band was expanded once before by the Commission, from \$0.07 per therm to \$0.10 per therm, and 'Staff is not conceptually opposed to a possible expansion of the band' (Ex. A-15, at 5). However, we believe the Company's proposed increase to \$0.20 is excessive. We find that an increase to \$0.13 per therm reflects a more reasonable balance between the interests of the Company and its customers.

Officer Certification of Monthly PGA Reports

[58, 59] Staff recommends that an officer of Southwest Gas be required to certify, under oath, through an affidavit attached to each adjustor report, that all information provided in the adjustor report is true and accurate to the best of his or her information and belief. Mr. Gray stated that this recommendation is consistent with action taken by the Commission in other gas and electric cases dealing with adjustor mechanisms (Ex. A-13, at 24-25). Staff does not believe there is any basis for Southwest Gas to be treated differently than the other companies that are required to provide such certification (Ex. A-15, at 5).

Southwest Gas opposes Staff's recommendation to require officer certification of the monthly PGA reports. Company witness Moody testified that although Southwest Gas is committed to providing the Commission with accurate information, the Company does not believe the certification requirement is necessary. Southwest Gas believes the person most knowledgeable regarding the report should sign it, as opposed to an officer (Ex. A-22, at 7; Tr. 454-455).

We do not believe it is an undue burden for an officer of Southwest Gas to be required to familiarize herself or himself with the workings of the PGA mechanism and the monthly reports that are filed to support the required information. While Southwest Gas argues that Staff failed to provide a valid reason for why this requirement is necessary, the underlying basis of the Company's opposition rings hollow. The officer certification requirement would not only put Southwest Gas in a position that is comparable to other companies for which the issue has been addressed, but will provide a measure of assurance to the Commission, as well as the Company's customers and shareholders, that a level of oversight exists that reaches to the Company's highest ranks. Although we are not suggesting that Southwest Gas' prior PGA reports have been deficient, given the financial accounting scandals that have been exposed in the recent past, certification of a report that deals with millions of dollars of gas costs on a monthly basis seems a small price to pay for a higher level of oversight. Indeed, it is surprising that AUIA has not taken a position in support of Staff's recommendation given the inherent interest of shareholders in transparency and accountability for a publicly filed report regarding the Company's purchased gas costs. We will therefore adopt Staff's recommendation.

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Gas Procurement Practices

Staff witness Gray and William Gehlen conducted a detailed review of Southwest Gas' procurement practices during the test year, and offered several recommendations with respect to those practices. Mr. Gray identified price stability as one of the Commission's goals of the gas procurement process for Arizona LDCs, including Southwest Gas (See, Decision No. 61225).

Staff witness William Gehlen testified regarding the Company's procurement practices and indicated that having a mix of spot market gas and long-term fixed price contracts enhances price stability (Ex. S-8). Staff recommended that Southwest Gas further explore procurement opportunities in order to enhance greater price stability for customers. According to Staff, the Company has agreed to a number of recommendations, including: conducting a fuel and procurement practice best practices review; separating the contract award group from the invoice approval authority within the Company; reviewing the Company's portfolio evaluation software; eliminating the use of cell phones in term bidding and negotiating activities; and having a neutral party observe these activities (Tr. 433-434).

It is also Staff's position that employees involved in gas procurement should not have 'substantial' stock ownership in companies with which it is dealing (Tr. 1108). Company witness Moody agreed that Southwest Gas would review its definition of stock ownership rules for employees involved in gas procurement and meet with Staff within 60 days of the Decision in this case (Tr. 434).

Mr. Moody also agreed Southwest Gas shares Staff's concerns regarding El Paso, shortfall of service, and other lateral issues. It is Staff's recommendation that Southwest Gas should construct and own its laterals absent a compelling reason to do otherwise. However, Mr. Moody indicated that the best course of action is to take a look at a cost-effective and reasonable means for the Company to either own its system or own access to supplies that come onto its system. He explained that the Company has a long history of trying to purchase laterals from El Paso, but to do so would often require also purchasing undesirable lateral facilities (Tr. 455-456).

Although there does not appear to be any dispute between the Company and Staff regarding these gas procurement issues, we direct the Company to initiate discussions with Staff, within 60 days of this Decision, regarding the stock ownership issues discussed above, and to continue to cooperate with Staff regarding other procurement issues, including issues pertaining to El Paso and construction and ownership of laterals on the Company's system. Staff shall file within 180 days of the effective date of this Decision, as a compliance item in this docket, a report or reports regarding the stock ownership issues, procurement practices, benchmarking, and El Paso laterals issues discussed above.

Interest on Customer Deposits

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[60] In its Application, Southwest Gas proposed a reduction of the interest rate applied to customer deposits from 6 percent to 3 percent (Ex. A-29, at 31- 32). As noted above, Staff proposed that the interest rate on PGA balances be set based on a monthly one-year nominal Treasury constant maturity rate (Ex. S-13, at 22). Staff also recommends that the same interest rate be applied to the Company's other balancing accounts (i.e., DSM and LIRA) (Id. at 54). Company witness Congdon testified on rebuttal that an equitable approach to the customer deposit interest rate issue would be to synchronize the interest rates on both customer deposits and the balancing accounts maintained by Southwest Gas (Ex. A-17, at 39).

Staff witness Gray testified that Staff recommends maintaining the customer deposit interest rate at 6 percent consistent with the rate in effect for a wide variety of other utilities. Mr. Gray stated that although interest rates are currently relatively low, a significant rise in rates would not be equitable to customers if the customer deposit interest rate were reduced to 3 percent as requested by the Company (Ex. S-13, at 57).

We agree with Staff that the customer deposit interest rate should be maintained at the current level of 6 percent. We believe that subjecting such deposits to a constantly varying interest rate could lead to customer confusion and would be inconsistent with the practices in effect for other utilities in the State. We therefore adopt Staff's recommendation on this issue. We also agree with Staff that maintaining the 12-month customer deposit period is appropriate.

Four-Hour Service Window

[61] In his Direct testimony, Staff witness Gray indicated that the Commission's Consumer Services Division has received a number of customer contacts expressing concern that Southwest Gas asks customers to be available at the service location for most or all of a day when a technician is scheduled for service. Mr. Gray stated that the Company's policy imposed a burden on customers and is inconsistent with the practices of other gas and electric utilities, which provide a four-hour window for service calls. Mr. Gray pointed out that the service window length is not established by Commission rule, but is set according to each company's practice. Mr. Gray recommended that Southwest Gas be required to establish a company practice of giving customers a four-hour window, in accordance with the policies in effect for other similar utility companies (Ex. A-13, at 54-55). Mr. Gray stated that there is no compelling reason why Southwest Gas cannot adopt the four-hour standard and he recommends that the Commission order the Company to adopt such a standard within 6 months from the date of this Decision (Ex. A-15, at 14).

Company witness Palacios responded that a directive from the Commission is not necessary because Southwest Gas currently offers several service options including two-hour, four-hour, and eight-hour service windows 'based on the customer's request' (Ex. A-6, at 5). She indicated that only 10 to 15 percent of customers requesting service establishment (which requires entry into the premises) request service appointments of four hours or less. Ms. Palacios claims that if Staff's

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recommendation were adopted, Southwest Gas would likely have to increase its workforce to provide every customer, regardless of need, a four-hour service window (Id. at 4-5). She stated that such a mandate would also likely require significant restructuring of existing work practices and replacement of or major modification to the Company's customer appointment software. Ms. Palacios noted that gas utilities differ from electric companies because, for safety reasons, an employee must always enter the premises when service is established, and because service technicians must give their highest priority to emergencies which may interfere with their ability to meet four-hour window requirements (Id. at 6-7).

We do not believe that the four hour service window requirement recommended by Staff would place an onerous burden on the Company's customer service capabilities. Mr. Gray testified that the Commission's Consumer Services Division has received comments regarding the lack of such a window being offered, and Staff's proposal to allow Southwest Gas 6 months to develop a program to meet this requirement is a reasonable length of time for compliance. Although the Company's witness attempted to distinguish electric from gas service providers to support the Company's position, she failed to recognize that UNS Gas, Inc. ('UNS') has a tariff in effect that requires appointments to be scheduled 'within a maximum range of four (4) hours during normal working hours' unless another time frame is established that is mutually agreeable to both UNS and the customer (Ex. S-27). Consistent with the tariff in effect for UNS, we agree with Staff that Southwest Gas should adopt a tariff which requires customers to be offered a maximum four-hour service window. Staff's recommendation is therefore adopted.

Energy Share Contributions

[62, 63] Southwest Gas currently participates in the Energy Share program, which allows customers the opportunity to make voluntary contributions to help other customers with financial difficulties pay their utility bills. Other companies, such as APS and Salt River Project, also participate in the program, which is administered by the Salvation Army.

Staff witness Gray stated that Southwest Gas currently provides customers with a separate bill insert that can be returned with donations for Energy Share. In comparison, APS provides a box on its actual bills that can be checked and an amount indicated for donation. Staff recommends that, at the time the new rates from this proceeding are reflected on customer bills, Southwest Gas should provide a place on its customer bills to allow donations to the Energy Share program (Ex. S-13, at 55-56).

In response, Company witness Congdon testified that Southwest Gas strongly supports retention of allowing customer contributions via bill inserts. He stated that the current practice should be maintained 'unless Staff presents clear and convincing evidence that a change in the program notification process would result in a greater benefit than its cost' (Ex. A-17, at 38).

We believe Staff's recommendation should be adopted. We appreciate Southwest Gas'

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participation in the Energy Share program. However, we agree with Staff that inclusion of a line on customer bills is preferable to a bill insert, which may be discarded when customers open their bills. We do not believe that a cost/benefit analysis is necessary to recognize that contributions are likely to be enhanced if, at the time customers sit down to write out their monthly checks, the opportunity to donate is clearly shown on the billing statements alongside the amount due. We believe Staff's recommendation represents a common sense approach to encouraging contributions to the program. The Company should implement this change within 60 days of the effective date of this Decision.

Gas Technology Institute

[64, 65] The Gas Technology Institute ('GTI'), which was formerly known as the Gas Research Institute, is a non-profit entity that does research, development and training regarding energy markets. GTI's Operations Technology Development ('OTD') programs focus on projects pertaining to pipe and leak locating and detection, reduced construction costs, gas main integrity and safety, while its Utilization Technology Development ('UTD') program focuses on developing increased-efficiency and safety end-use equipment for residential, commercial, and industrial gas customers. Although GTI was previously funded through a FERC **surcharge**, it now must solicit donations via state public utilities commissions and the LDCs they regulate (Ex. S-13, at 2-8).

Staff recommends that Southwest Gas participate in funding GTI's OTD and UTD programs at a level of \$688,712 annually, which amount would be recovered on a per therm basis from the Company's sales customers, excluding G-30 and B-1 customers. Mr. Gray stated that the per therm **surcharge** would amount to approximately \$0.00113, which would increase an average residential customer's bill by approximately three cents per month (Id.).

Southwest Gas witness Marti Marek testified that the Company supports funding gas research but opposes Staff's mandatory contribution of all research funding to a single entity. She indicated that, although the Company is pleased with the projects it has participated in with GTI, there are other competing research organizations that perform equally valuable work (Ex. A-24, at 2-6).

We agree with Southwest Gas that the funding provided for research should not be allocated to a single entity. The Company should have flexibility to tailor the research funds to the projects and organizations best suited for a specific need, subject to oversight by the Commission (Id. at 7). We will therefore adopt the recommended level of research funding, which would be collected through a surcharge, and held and disbursed through a balancing account. Adoption of Southwest Gas' proposal will allow the Company flexibility to select specific projects on a case-by-case basis, but will permit Staff to have input and oversight regarding the program expenditures.

Demand Side Management/Energy Efficiency Programs

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[66, 67] Southwest Gas proposed increasing its current level of demand side management ('DSM') funding of \$600,000 per year to \$4,385,000 annually [FN15] , subject to the Commission's approval of a decoupling mechanism. The DSM programs would be directed at all classes of customers instead of just residential customers as currently exists. The specific programs, and the associated funding proposed by Southwest Gas are as follows: Low-Income Energy Conservation ('LIEC') (\$500,000); Energy Star Home Certification (\$250,000); Multi-Family New Construction (\$1,200,000); Residential Energy Construction (\$200,000); Energy Star Appliances (\$800,000); Food Service Equipment (\$500,000); Efficient Commercial Building Design (\$500,000); Technology Information Center (\$35,000); and Distributed Generation (\$400,000).

Staff, RUCO, and SWEEP/NRDC all support the DSM programs proposed by the Company, with a few minor exceptions. SWEEP/ NRDC witness Schlegel recommended that an additional \$750,000 should be added to the Energy Star Home Certification program, and that Southwest should be allowed to impose a performance incentive mechanism to recover up to 10 percent of DSM funding if minimum goals are met (SWEEP Ex. 1, at 6). Company witness Vivian Scott testified in support of SWEEP/NRDC's proposals because she believes increasing funding for the Energy Star Home Certification program would enable the Company to expand the program to larger parts of its service territory (currently offered only in the Tucson area) (Ex. A-15, at 3). She also supports the performance incentive mechanism proposal which is comparable to a program in effect for APS (Id.).

Staff witness Steve Irvine supports the Company's initial proposed DSM funding level, with the exception of \$50,000 included in the LIEC program that is specifically allocated for rate assistance to low-income customers. Mr. Irvine stated that such rate assistance is not DSM-related and should therefore be considered as a separate and distinct program (Ex. S-19, at 3). He acknowledged that a similar program was included in a recent APS case, but points out that the rate assistance component of that case was part of a settlement agreement involving a number of diverse parties. Mr. Irvine also opposes the SWEEP/NRDC proposal to increase the Energy Star Home Certification program by \$750,000 on the basis that Southwest Gas previously indicated that 'the market has sufficiently transformed and that incentives are no longer necessary to ensure more energy-efficient construction' (Id. at 6) (See also, Decision No. 67878, June 1, 2005, granting Southwest Gas' request to reduce the annual Energy Advantage Plus program funding from \$900,000 to \$250,000). In addition to these adjustments to proposed DSM revenues, Staff recommends the following with respect to the Company's DSM programs: semi-annual DSM reports certified by an officer of the Company; requirement that Company docket within 120 days of this Decision, in a separate docket, detailed descriptions of the DSM programs that would be subject to Commission approval; requirement that the Company implement and maintain the collaborative DSM working group to solicit and facilitate input from any interested party (prior to submission to Commission of specific programs); responsibility of Southwest Gas to demonstrate appropriateness of specific DSM programs; and no performance incentive mechanism should be approved (Id. at 9-10).

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With one exception, we agree with Staff's recommendations regarding DSM. Despite Staff's concerns, we believe the \$50,000 currently included in the LIEC program for rate assistance funding should be maintained. Although such funding may not in a strict sense be considered DSM-related, we agree with Mr. Schlegel that it represents a relatively small percentage of the overall DSM budget and is to be used for emergency situations for low-income customers. To the extent any portion of this \$50,000 is not spent yearly on bill assistance emergencies, the balance should be allocated to general LIEC programs. With respect to SWEEP/NRDC's proposal to increase by \$750,000 funding for Energy Star Home Certification, we share Staff's concern that the Company has previously offered conflicting views of whether such an increase in such funding would be cost effective. As Mr. Irvine pointed out, through data request responses the Company indicated that it could offer the program throughout its service area at the initial funding level and specifically requested a reduction in funding for a similar program in the Tucson area due to market transformation (Ex. S-19, at 6-7). We also agree with Staff that the performance incentive mechanism, which was suggested for the first time in Mr. Schlegel's testimony, is not sufficiently developed for approval at this time. The parties to the DSM collaborative process may wish to pursue this issue through further discussions but the proposal contained in the record of this proceeding lacks sufficient detail to determine whether it is appropriate at this time. In all other respects, we agree with and adopt Staff's recommendations as described above.

* * * * *

Having considered the entire record herein and being fully advised in the premises, the Commission finds, concludes, and orders that:

FINDINGS OF FACT

1. On December 9, 2004, Southwest Gas filed an application with the Commission for an increase in rates.
2. On January 7, 2005, the Commission's Utilities Division Staff filed a Letter of Insufficiency.
3. On January 26, 2005, Staff filed a Letter of Sufficiency, notifying the Company that its application met the sufficiency requirements and classifying Southwest Gas as a Class A utility.
4. By Procedural Order issued February 7, 2005, procedural timeframes were established and a hearing was scheduled to commence on October 3, 2005.
5. Intervention was granted to RUCO, AUIA, DOD, SWEEP/NRDC, YCA, ACAA, APS, and TEP.
6. Southwest Gas filed Direct testimony with its application on December 9, 2004. Pursuant to Procedural Order issued March 10, 2005, Direct testimony was filed on

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July 26, 2005 by Staff, RUCO, YCA, AUIA, ACAA, and SWEEP/NCRA.

7. Rebuttal testimony was filed by Southwest Gas on August 23, 2005. Surrebuttal testimony was filed on September 13, 2005 by Staff, RUCO, AUIA, SWEEP/NRDC, and DOD. Rejoinder testimony was filed by the Company on September 23, 2005.

8. An evidentiary hearing was conducted at the Commission's offices in Phoenix, Arizona commencing on October 3, 2005 and concluding on October 11, 2005.

9. Late-filed exhibits were filed by Southwest Gas on October 21, 2005 and November 4, 2005.

10. Initial Post-Hearing Briefs were filed by DOD on October 31, 2005, by RUCO on November 3, 2005, and on November 4, 2005 by Southwest Gas, SWEEP/NRDC, AUIA, and Staff.

11. Reply Briefs were filed on November 14, 2005 by Southwest Gas, RUCO, SWEEP/NRDC, AUIA, and Staff. Southwest Gas filed a Supplement to its Reply Brief on November 23, 2005.

12. According to the Company's application, as modified, in the test year Southwest Gas had adjusted operating income of \$46,775,622 on an adjusted Original Cost Rate Base of \$943,110,070, for a 4.96 percent rate of return.

13. In its application, as modified, the Company requested a revenue increase of \$66,898,342, based on OCRB of \$943,110,070, and rate of return of 9.24 percent.

14. Staff recommends a rate increase of \$51,625,135, based on OCRB of \$924,927,566, and a recommended rate of return of 8.40 percent.

15. RUCO recommends a revenue increase of \$48,506,079, based on OCRB of \$919,607,846, and recommended rate of return of 8.64.

16. For purposes of this proceeding, we determine that Southwest Gas has an Arizona Fair Value Rate Base of \$1,169,584,038.

17. A rate of return on FVRB of 6.63 percent is reasonable and appropriate.

18. Southwest Gas is entitled to a gross revenue increase of \$49,345,636.

19. The Company's proposed Conservation Margin Tracker decoupling mechanism proposal is not adopted in this proceeding.

20. The class responsibility for the revenue requirement should be allocated using the methodology of Staff's rate design expert witness.

21. For residential customers under Schedule G-5, the basic monthly customer charge should be increased from \$8.00 to \$9.70, and a two-tier declining block

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structure remains appropriate in accordance with Staff's recommendation.

22. A separate multi-family residential basic monthly customer charge of \$8.70 is appropriate under the new Schedule G-6 rate.

23. The low-income residential rate (G-10) should be maintained at its current \$7.00 per month with the current commodity discount of 20 percent for the first 150 therms of winter usage.

24. Staff's rate design recommendations for Special Residential Gas Service for Air Conditioning (G-15) and Master Metered Mobile Home Park Gas Service (G-20) should be adopted.

25. The current Armed Forces Rate Schedule G-35 should be eliminated and customers currently on that schedule would receive service under Schedule G-25.

26. For General Gas Service customers on Schedule G-25, a new sub-class should be created for small customers using less than 600 therms annually, and the demand charge for large G-25 customers should be calculated based on DOD's recommendation of using a modified non-coincident peak during any winter month.

27. For Air Conditioning Gas Service (G-40); Gas Service for Compression on Customer's Premises (G-55); Cogeneration Gas Service (G-60); Small Essential Agricultural User Gas Service (G-75); and Natural Gas Engine Gas Service (G-80), Staff's recommended rate design should be adopted.

28. The billing determinants proposed by the Company should be employed for setting rates in this proceeding.

29. With respect to the Company's Purchased Gas Adjustor mechanism, the base cost of gas should be set at zero in accordance with Staff's recommendation; the trigger level for the PGA bank balance should be increased from \$22.4 million to \$29.2 million as recommended by Staff; and the current \$0.10 per therm adjustment band should be increased to \$0.13 per therm.

30. The interest rate for the Company's PGA, DSM, and LIRA balancing accounts should be based on the one-year nominal Treasury constant maturities rate, in accordance with Staff's recommendation.

31. The Company's PGA monthly reports to the Commission should continue to comply with all current reporting requirements and include the beginning bank balance, any offsets, and the ending bank balance.

32. Staff's recommendation to require an officer of Southwest Gas to provide certification of the accuracy of the monthly PGA reports is reasonable and should be adopted.

33. Southwest Gas should initiate discussion with Staff within 60 days regarding

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gas procurement issues identified by Staff, including issues pertaining to El Paso and construction and ownership of laterals on the Company's system.

34. The current interest rate of 6 percent on customer deposits should be maintained in accordance with Staff's recommendation. The 12-month customer deposit period should also be maintained.

35. Southwest Gas should develop within 6 months a tariff proposal that would require that customers be offered a four-hour window for service calls.

36. Southwest Gas should implement, within 60 days of the effective date of this Decision, Staff's recommendation to allow donations to the Energy Share program by an indication on the Company's billing statements.

37. Gas research should be funded at the level recommended by Staff, but Southwest Gas should have the flexibility, subject to Staff oversight, to select appropriate entities for use of the research funds.

38. DSM programs should be funded at the level initially recommended by Southwest Gas (\$4,385,000) and the Company should comply with the recommendations made by Staff regarding, among other things, compliance filings and working with the DSM collaborative group.

39. Arizona customer bills should contain information relevant to Arizona customers. Information specific only to Nevada and/or California customers should be removed from the back of Arizona customer bills. Furthermore, the back of Arizona customer bills should contain explanations for two billing line items 'Base Tariff Rate' and 'Rate Adjustment.'

40. We also agree with Staff that anytime Southwest Gas initiates participation in a new natural gas docket at the FERC which relates to its service in Arizona, the Company should be required to provide Staff with a copy of Southwest Gas' initial filing in that FERC docket.

CONCLUSIONS OF LAW

1. Southwest Gas is a public service corporation within the meaning of Article XV of the Arizona Constitution and A.R.S. §§ 40-250, 40-251 and 40-367.

2. The Commission has jurisdiction over Southwest Gas and the subject matter contained in the Company's rate application.

3. The rates, charges and conditions of service established herein are just and reasonable and in the public interest.

ORDER

IT IS THEREFORE ORDERED that Southwest Gas Corporation is hereby authorized and

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directed to file with the Commission, on or before February 28, 2006, revised schedules of rates and charges consistent with the discussion herein and a proof of revenues showing that, based on the adjusted test year level of sales, the revised rates will produce no more than the authorized increase in gross revenues.

IT IS FURTHER ORDERED that the revised schedules of rates and charges shall be effective for all service rendered on and after March 1, 2006.

IT IS FURTHER ORDERED that Southwest Gas Corporation shall notify its customers of the revised schedules or rates and charges authorized herein by means of an insert in its next regularly scheduled billing, in a form acceptable to Staff.

IT IS FURTHER ORDERED that, in its next rate case, Southwest Gas Corporation shall provide a detailed explanation of employee duties that are associated with sales, marketing, or promotional activities and offer a reasonable allocation of wage expense consistent with those duties.

IT IS FURTHER ORDERED that, in its next rate case, Southwest Gas Corporation shall provide a clearer picture of AGA functions and how the AGA's activities provide specific benefits to the Company and its customers.

IT IS FURTHER ORDERED that Southwest Gas Corporation should coordinate its efforts to pursue implementation of a decoupling mechanism through discussions with Staff, RUCO, SWEEP/NRDC, and any other interested parties. Such efforts may be pursued through the DSM policy process, as suggested by SWEEP/NRDC, and through a proposal in the Company's next rate case.

IT IS FURTHER ORDERED that Southwest Gas Corporation shall submit to Staff for its review a copy of all customer education materials related to setting the base cost of gas at zero prior to the materials being distributed to customers.

IT IS FURTHER ORDERED that the Company's PGA monthly reports to the Commission shall continue to comply with all current reporting requirements and include the beginning bank balance, any offsets, and the ending bank balance.

IT IS FURTHER ORDERED that, for all future PGA monthly reports, an officer of Southwest Gas shall be required to certify, under oath, through an affidavit attached to each adjustor report, that all information provided in the adjustor report is true and accurate to the best of his or her information and belief.

IT IS FURTHER ORDERED that Southwest Gas Corporation shall initiate discussions with Staff, within 60 days of this Decision, regarding the stock ownership issues discussed herein, and to continue to cooperate with Staff regarding other procurement issues, including issues pertaining to El Paso and construction and ownership of laterals on the Company's system.

IT IS FURTHER ORDERED that Staff shall file within 180 days of the effective date of this Decision, as a compliance item in this docket, a report or reports

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regarding the stock ownership issues, procurement practices, benchmarking, and El Paso laterals issues discussed above.

IT IS FURTHER ORDERED that Southwest Gas Corporation shall, within 6 months of the effective date of this Decision, propose a tariff which requires customers to be offered a maximum four-hour service window.

IT IS FURTHER ORDERED that Southwest Gas Corporation shall implement, within 60 days of the effective date of this Decision and in a form acceptable to Staff, Staff's recommendation to allow donations to the Energy Share program by an indication on the Company's billing statements.

IT IS FURTHER ORDERED that Southwest Gas Corporation shall comply with the recommendations made by Staff regarding, among other things, DSM compliance filings and working with the DSM collaborative group.

IT IS FURTHER ORDERED that this Decision shall become effective immediately.

FOOTNOTES

FN1 Other intervenors in the proceeding raised non-revenue requirement issues which are discussed below.

FN2 The defective pipe was 1960s steel pipe, and plastic pipe known as Aldyl A, Aldyl HD, and ABS.

FN3 Application of Southwest Gas Corporation for Increase in Rates, Public Utilities Commission of Nevada, Order in Docket No. 04-3011 (August 30, 2004), at 41.

FN4 Federal Power Commission et al. v. Hope Natural Gas Co., 320 U.S. 591 (1944); Bluefield Waterworks & Improvement Co. v. Public Service Commission of West Virginia, et al., 262 U.S. 679 (1923).

FN5 Southwest Gas proposed that if the CMT were adopted, the basic monthly charge should be increased from \$8 to \$12 per month, and the commodity charge would increase from \$0.49 to \$0.84 in the first block, and would decrease from \$0.40 to \$0.15 in the second block. Because we have not adopted the CMT, the rate design proposal described above is recommended by the Company.

FN6 RUCO claims that its recommendation would shift approximately \$23 million per year from commodity charges to the basic service charge under current revenues and over \$26 million under RUCO's proposed revenues in this case (Tr. 1003-1004).

FN7 An estimate of the seasonal impact of the increase can best be seen by viewing an average customer's summer usage in August (10 therms), where an average bill would increase by 11.8 percent, from \$18.94 to \$21.18; and an average customer's winter usage in January (72 therms), where an average bill would increase by 8.1

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(Publication page references are not available for this document.)

percent, from \$84.04 to \$90.83.

FN8 An estimate of the seasonal impact of the increase can best be seen by viewing an average customer's summer usage in August (10 therms), where an average bill would increase by 5.9 percent, from \$18.94 to \$20.06; and an average customer's winter usage in January (72 therms), where an average bill would increase by 6.1 percent, from \$84.04 to \$89.14.

FN9 Decision No. 58377 concurred with Staff's recommendation 'to retain the current SEA [small essential agriculture] rate schedule' (Decision No. 58377, at 42-43). Although the Decision directed Southwest Gas to 'gradually move the SEA schedule to the general service level,' the Commission specifically rejected Southwest Gas' request to close the small essential agriculture tariff to new customers because 'closure may unfairly treat identical customers' (Id. at 43). Contrary to the Company's assertion in its Brief, the Commission did not state in Decision No. 58377 that Schedule G-75 should be eliminated.

FN10 Mr. Congdon stated that Staff accepted the Company's proposed test year bills and volumes, but not all of the Company's proposed reclassifications of customers to new rate schedules. The Company agreed that, to the extent Southwest Gas' proposed rate schedules and customer reclassifications are not adopted, use of Staff's bills and volumes would be appropriate (Ex. A-17, at 26). To the extent we have adopted Staff's recommendations on the various rate schedule issues, as discussed above, Staff's bills and volumes will be employed accordingly.

FN11 Customers under Schedules G-60 and G-80 are served under a separate cost of gas which is reset twice annually, on April 1st and October 1st (Ex. A-13, at 8).

FN12 The base cost of gas includes both the commodity cost and the cost of transport from its source to the Southwest Gas distribution system.

FN13 Specifically, Staff recommends that Southwest Gas' report include a breakdown of 'purchases' into fixed price and variable (such as index) contracts, and that the Company begin identifying in its monthly PGA reports average and median usage levels for G-5 and G-10 rate schedules (Ex. A-13, at 25).

FN14 Southwest Gas initially proposed a corresponding increase in the adjustment band of only three cents, from \$0.10 to \$0.13 (Ex. A-17, at 40).

FN15 The DSM funds are collected through a DSM surcharge and held and disbursed through a balancing account.

EDITOR'S APPENDIX

PUR Citations in Text

[ARIZ.] Re Southwest Gas Corp., 146 PUR4th 54, Docket No. U-1551-92-253, Decision No. 58377, Aug. 12, 1993.

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(Publication page references are not available for this document.)

[ARIZ.] Re Southwest Gas Corp., 156 PUR4th 109, Docket No. U-1551-93- 272, Decision No. 58693, July 7, 1994.

[ARIZ.] Re Southwest Gas Corp., 213 PUR4th 53, Docket Nos. G-01551A-00- 0309, G-01551A-00-0127, Decision No. 64172, Oct. 30, 2001.

[NEV.] Re Southwest Gas Corp., 236 PUR4th 294, Docket No. 04-3011, Aug. 26, 2004.

[U.S.Sup.Ct.] Bluefield Water Works & Improv. Co. v. West Virginia Pub. Service Commission, 262 U.S. 679, PUR1923D 11, 67 L.Ed 1176, 43 S.Ct. 675 (1923).

[U.S.Sup.Ct.] Federal Power Commission v. Hope Nat. Gas Co., 320 U.S. 591, 51 PUR NS 193, 88 L.Ed 333, 64 S.Ct. 281 (1944).

[U.S.Sup.Ct.] West Ohio Gas Co. v. Ohio Pub. Utilities Commission, 294 U.S. 63, 6 PUR NS 449, 79 L.Ed.2d 761 (1935).

END OF DOCUMENT

**BEFORE THE PUBLIC SERVICE COMMISSION
OF UTAH**

IN THE MATTER OF:

Joint Application of Questar Gas	)	
Company, the Division of Public	)	
Utilities, and Utah Clean Energy	)	Docket Number 05-057-T01
For the Approval of the Conservation	)	
Enabling Tariff Adjustment Option	)	
And Accounting Orders	)	

**DIRECT TESTIMONY
OF
DAVID E. DISMUKES, PH.D.**

**ON BEHALF OF THE
UTAH COMMITTEE OF CONSUMER SERVICES**

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DIRECT TESTIMONY OF
DAVID E. DISMUKES, PH.D.
ON BEHALF OF
UTAH COMMITTEE OF CONSUMER SERVICES
DOCKET NO. 05-057-T01

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 professional resume that

includes a complete list of my publications, presentations, and pre-filed expert witness testimony, expert reports, expert legislative testimony, and affidavits.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. I have been retained by Utah Committee of Consumer Services (“Committee”) to provide an expert opinion on whether or not Questar Gas Company’s (“Questar” or “the Company”) Conservation Enabling Tariff (“CET”) should be continued.

Q. HOW IS THE REMAINDER OF YOUR CURRENT TESTIMONY ORGANIZED?

A. My testimony is organized into the following sections:

- Section II: Summary of Recommendations;
- Section III: Procedural History;
- Section IV: Overview of Revenue Neutrality Mechanisms;
- Section V: Maintaining the CET Would Not Be in the Public Interest and Should be Discontinued;
- Section VI: Direct Ratepayer Benefits of the CET are Small
- Section VII: Alternative Remedies for Dealing with Energy Efficiency Disincentives;
- Section VIII: Alternative Methods for Dealing with Declining Use Per Customer;
- Section IX: Conclusions and Recommendations.

Q. HAVE YOU PROVIDED ANY ATTACHMENTS TO YOUR TESTIMONY?

46 A. Yes, I have included two attachments to my testimony which include my
47 professional resume and a summary overview of state decisions where revenue
48 decoupling was rejected or withdrawn. .

49 **Q. HAVE YOU PROVIDED ANY EXHIBITS TO YOUR TESTIMONY?**

50 A. Yes, I have prepared 17 exhibits to accompany my testimony. The
51 exhibits were prepared by me or under my direct supervision.

52 **II. SUMMARY OF RECOMMENDATIONS**

53 **Q. WHAT IS YOUR GENERAL RECOMMENDATION IN THIS**
54 **PROCEEDING?**

55 A. The CET should be discontinued on a forward going basis. In examining
56 the Company's potential revenues at risk, it is clear at this time that the most
57 significant challenge it faces is a potential exposure to future revenue losses
58 resulting from declines in use per customer rather than large revenue losses
59 associated with the promotion of Demand-Side Management ("DSM") programs.
60 Revenue losses resulting from DSM programs are estimated to be less than one-
61 half of one percent; thus, they are simply not that significant and can be easily
62 accommodated within a straightforward lost revenues adjustment mechanism.

63 **Q. HOW CAN A DECLINE IN USE PER CUSTOMER CREATE RISKS FOR**
64 **A COMPANY THAT IS SEEING STRONG REVENUE GROWTH RIGHT NOW?**

65 A. Revenue changes, as I will discuss later in my testimony, have two related
66 parts that involve both (1) changes in use per customer and (2) changes in the
67 number of customers. Currently, revenues are increasing due to rapid customer
68 growth. The Company's problem appears to stem from the relationship between

the marginal increase in revenues associated with new customers and a much higher marginal increase in investment cost per customer.

Q. SHOULDN'T THE COMPANY BE GIVEN AN OPPORTUNITY TO EARN ITS ALLOWED RETURN?

A. Yes, but it is my recommendation that the CET is not the appropriate mechanism to use for maintaining this opportunity. As I discuss in my testimony, there are a wide range of other regulatory mechanisms that can address these ratemaking and cost-recovery problems.

Q. HAS THE COMPANY'S EARNINGS SUFFERED DUE TO THESE CHANGES IN USE PER CUSTOMER?

A. No. The Company's earnings have not suffered primarily because revenues from overall customer growth have been so significant. Over the past five years, the Company's Utah jurisdictional DNG related return on equity (ROE) has been between 9.06 and 11.09 percent. In 2006, the Company's earnings were 10.86 percent compared to its currently allowed return of 11.2 percent. Earnings for 2007 are forecasted to be 10.32 percent.

Q. WHAT ARE YOUR FUNDAMENTAL OBJECTIONS TO THE USE OF REVENUE DECOUPLING MECHANISMS LIKE THE CET?

A. Revenue decoupling mechanisms are overly broad and shift considerable usage-related risks from the Company and its shareholders to ratepayers. Mechanisms like the CET eliminate a customer's ability to fully realize the complete benefits of their actions to reduce consumption in this high energy price

environment. This is neither fair nor efficient since over the long run it can dampen customers' incentives to reduce consumption.

Q. DO YOU SEE DECOUPLING AS PART OF A BROADER TREND IN UTILITY REGULATORY PROPOSALS?

A. Yes. As I will discuss later in my testimony, revenue decoupling is part of a broader set of policy initiatives offered by utilities which shift risk from shareholders to ratepayers. Some of these proposals in gas industry regulation include:

- (1) The creation of gas cost recovery ("GCR") mechanisms;
- (2) The creation of weather normalization clauses;
- (3) The recovery of Lost and Unaccounted for Gas ("LAUF") in GCRs;
- (4) The creation of pipeline replacement cost recovery riders;
- (5) Shorter weather normalization periods.

Some of the recent proposals in electric industry regulation include:

- (1) Bonus or incentive ROEs on the construction of baseload power plants;
- (2) Cash earnings on Construction Work in Progress ("CWIP") on nuclear power plants and other baseload generation investments;
- (3) Cash earnings on CWIP for power transmission investments;
- (4) Antecedent prudence reviews on major capital projects;
- (5) Shorter weather normalization periods.

Q. DO YOU HAVE ANY CONCERNS ABOUT THESE TYPES OF PROPOSALS?

114 A. Yes, these types of proposals raise questions about the proper risk
115 sharing relationship between ratepayers and shareholders. In reviewing several
116 of these types of proposals in both the gas and electric industry, my concern is
117 (1) the precedent-setting nature of the decisions, (2) their piecemeal adoption,
118 and (3) the potential movement down a slippery slope of disjointed policy
119 mechanisms that have interactive and unintended rate implications for
120 ratepayers. One particular concern I have is that many of these proposals fail to
121 attempt to make any ratemaking adjustment for this fundamental shift in risk from
122 shareholders to ratepayers..

123 **Q. WHAT ARE YOUR SPECIFIC RECOMMENDATIONS IN THIS**
124 **PROCEEDING?**

125 A. I have three primary recommendations:

126 (1) The Commission should discontinue the use of the CET since it
127 shifts considerable sales risk to ratepayers with little to no offsetting
128 benefits for ratepayers assuming those risks. Further, the CET is
129 overly broad in addressing the problems associated with declining
130 use per customer trends and is unnecessary to address incentive
131 issues associated with the promotion of DSM programs.

132 (2) The Commission should adopt a lost revenue adjustment ("LRA")
133 mechanism to make the Company whole for changes in usage
134 resulting from its DSM programs. Lost revenue recovery should be
135 tied directly to the estimates included in the Company's DSM cost-
136 effectiveness filings, and updated according to the ongoing

monitoring and verification (M&V) process.

- (3) The Commission should direct the Company to address any financial challenges created by decreases in use per customer in its next rate case through the use of a forecasted test year or some known and measurable adjustment if a historic test year is utilized for ratemaking purposes.

Q. DO YOU HAVE ALTERNATIVE RECOMMENDATIONS?

A. Yes, should the Commission reject my primary recommendations and decide to maintain the CET I would recommend:

- (1) The Commission require the CET to be modified such that decoupling true-ups are based upon the difference in historic and actual use per customer times test year customers (or base year customers upon which the revenue per customer statistic is derived) rather than actual customers.

- (2) The Commission should explicitly recognize the risk shifting nature of the CET and indicate in its Order that this shifting of risk will be considered in setting the Company's ROE in its next rate case.

III. PROCEDURAL HISTORY

Q. WOULD YOU PLEASE DISCUSS YOUR UNDERSTANDING OF THIS PROCEEDING'S ORIGINS?

A. On December 16, 2005, the Company, the Division of Public Utilities ("the Division") and Utah Clean Energy ("UCE") filed a Joint Application requesting approval of a Conservation Enabling Tariff ("CET") and other enabling accounting

mechanisms and proposals. The Joint Applicants offered the CET proposal to remedy what they saw as two fundamental problems confronting the Company. The first problem was the purported financial disincentive related to the promotion of DSM programs. The second problem was the claimed financial challenges stemming from a declining use per customer trend.

**Q. WERE YOU ASKED BY THE COMMITTEE TO OFFER AN EXPERT
OPINION ON THE CET PROPOSAL?**

A. Yes. I provided rebuttal testimony to the Joint Applicants on May 15, 2006. It was my expert opinion and recommendation that the Commission reject the CET proposal as not being in the public interest. My testimony stated:

(1) The CET represented a significant change in ratemaking and shifted risk to customers without any corresponding offset or benefit like a reduction on the overall allowed rate of return. It was, and still is my opinion, that the benefits of the CET are clear for Questar, but questionable for ratepayers.

(2) The CET proposal, as a mechanism to support DSM and declining use per customer trend, was based upon a questionable premise of disincentives. For instance:

a. Utilities have an obligation to provide least-cost reliable service, and if DSM is the least cost resource, utilities are obligated to acquire that resource.

b. If utilities experience a decline in earnings from declining use per customer, they have the option of seeking rate relief.

(3) There are a number of other, less dramatic regulatory mechanisms that can adjust utility rates for changes in usage created by either long run trends in overall efficiency or the Company's DSM programs.

Q. HAS YOUR EXPERT OPINION CHANGED SINCE FILING YOUR TESTIMONY LAST YEAR?

A. No. My expert opinion has not changed. I continue to believe that the CET is not a positive rate design change for ratepayers. I recommend that the Commission discontinue its use on a forward-going basis.

Q. DID YOU OFFER ANY ADJUSTMENTS OR ALTERNATIVES TO THE CET AS A RESULT OF THE JUNE 7, 2006 TECHNICAL CONFERENCE?

A. The Commission's Staff requested that parties provide a number of potential alternatives to the proposed CET during the course of the June 7, 2006 Technical Conference. This request was part of a larger set of questions submitted by Commission Staff to parties for comment relative to the CET. I provided Supplemental Testimony responding to all of these questions, including a number of possible alternatives to the CET. The two alternatives that I provided at that time were: (1) an incentive-based system where a utility's reward increases as it secures greater levels of cost-effective DSM savings; and (2) a "statistical recoupling" mechanism that would attempt to re-couple some of the exogenous factors (changes in gas commodity prices, economy, weather, etc.) impacting revenue back onto the Company and its shareholders.

IV. OVERVIEW OF REVENUE NEUTRALITY MECHANISMS

Q. WOULD YOU PLEASE DEFINE REVENUE NEUTRALITY?

A. Revenue neutrality can be defined as a set of policy mechanisms that make a utility indifferent to its level of sales. Typically, these policy mechanisms establish rate designs that either (a) remove revenue recovery from sales through some kind of fixed charge or (b) true-up revenues to some target amount. The goal of revenue neutrality mechanisms has generally been to remove a utility's purported disincentive to promoting energy efficiency. Over time, revenue neutrality mechanisms began to be promoted as (a) more consistent with "sound economic principles," and (b) giving utilities a better opportunity to earn their authorized rates of return.

Q. IS REVENUE NEUTRALITY A NEW IDEA?

A. No. As a regulatory concept, revenue neutrality has been around for nearly twenty years. In fact, the first Energy Policy Act (of 1992) addressed revenue neutrality and required states to consider this mechanism in conjunction with integrated resource planning ("IRP") standards, which emphasized the use of demand-side resources in a manner comparable to traditional supply-side considerations. The purported goals of revenue neutrality policies then, as well as now, were to develop rate design approaches that supposedly make a utility indifferent between promoting energy efficiency and sales.

Q. WHAT TYPES OF POLICY MECHANISMS ARE USED TO PROMOTE REVENUE NEUTRALITY?

A. Since the early 1990s, a variety of different approaches to revenue neutrality have been adopted. The primary revenue neutrality methods being promoted in the natural gas industry include what are commonly referred to as

229 “revenue decoupling” (and its different forms) and “straight-fixed variable” (“SFV”)
230 rate design mechanisms.

231 **Q. HAS REVENUE NEUTRALITY BEEN WIDELY ADOPTED SINCE THE**
232 **PASSAGE OF EPACT 1992?**

233 A. No. The original impetus for revenue neutrality was in the electric power
234 industry. However, a combination of competition, a decades-long boom in the
235 U.S. economy, and low fossil fuel prices worked to diminish interest in revenue
236 decoupling throughout most of the 1990s. Recent increases in fossil fuel prices,
237 particularly natural gas, have renewed interest in this ratemaking concept,
238 particularly for natural gas LDCs, although several electric utilities are starting to
239 revisit the concept as well.

240 **Q. CAN YOU BRIEFLY DESCRIBE A SFV RATE DESIGN?**

241 A. A SFV rate design represents a dramatic change in the method in which
242 utilities charge their customers for distribution service. Common utility pricing
243 practice is based upon what is referred to as a “two-part tariff.” This two-part
244 tariff is comprised of a fixed customer charge and a per unit (volumetric) charge.
245 Natural gas commodity charges are also variable, and applied to customers’ bills
246 on a usage basis. A SFV rate design completely changes this pricing practice
247 and recovers all distribution (non-gas) charges on a fixed basis rather than the
248 commonly accepted two-part approach. Under SFV, the only variable charge the
249 customer will see is the commodity gas charges recovered through the gas cost
250 recovery (“GCR”) rate.

Q. EARLIER YOU MENTIONED THAT REVENUE DECOUPLING IS A FORM OF REVENUE NEUTRALITY. PLEASE EXPLAIN THE CONCEPT OF REVENUE DECOUPLING IN GREATER DETAIL?

A. Revenue decoupling is a form of revenue neutrality that changes the manner in which revenues are collected from ratepayers. Typically, rates are fixed and based upon an allowed rate of return (among other factors). While the allowed revenues included in this formula are considered fixed, actual revenues vary from year-to-year depending upon a wide range of factors. Revenue decoupling basically changes the nature of this process. Under a revenue decoupling regime, revenues are fixed and virtually guaranteed while rates are allowed to vary from year-to-year to assure a guaranteed level of revenue recovery.

Q. HOW DOES REVENUE DECOUPLING WORK?

A. Revenue decoupling is typically done on a revenue per customer basis where an allowed revenue per customer is established in a rate case, or some other agreed upon level. This allowed revenue per customer is then determined for every month of the year. Over time, the allowed revenue per customer is compared to the actual revenue per customer. If actual revenues are lower than allowed, the revenue shortfall is booked to a true-up account to be factored into rates. These true-ups can occur as frequently as every month, every quarter, or annually. The process is symmetrical – if revenues are greater than allowed, excess revenues are credited to the balancing account for a future rate decrease.

Q. CAN REVENUE DECOUPLING TAKE DIFFERENT FORMS?

A. Yes, there are two general forms of revenue decoupling: full revenue decoupling and partial revenue decoupling. Full decoupling allows the entire under or over-recovery of revenues to fall into a balancing account for later true up. Partial decoupling only allows some part of that overage/underage to enter the balancing account. In some instances, the balances are adjusted for changes in prices, weather, and/or the economy. That is, revenue changes related to gas commodity prices, the economy or weather are not eligible for recovery in the balancing account. This process can also be referred to as “statistical re-coupling” since estimates from statistical load forecasts are used to make the price, weather, and economic-related adjustments. Another form of partial decoupling can occur through a fixed cap percentage on revenue recovery. For instance, North Carolina has caps on total decoupling balance recoveries. The current interim approach in Utah also has a cap on total revenues that can be recovered in the decoupling balancing account.

Q. ARE SFV AND REVENUE DECOUPLING RELATED?

A. Somewhat. Revenue decoupling usually preserves the traditional rate design structure utilized by most state regulatory commissions where distribution service rates are comprised of a fixed customer charge and a volumetric distribution charge. Revenue decoupling sets a revenue per customer level to be recovered under these rates: if actual recovery falls below the target, then rates are increased in a subsequent period to make up for the shortfall and vice versa. Thus, one can think of revenue decoupling as creating a true-up process that sets variable rates at a level that makes customers indifferent between rates

being fixed or variable. SFV can be thought of as “perfect revenue decoupling” since rates are not required to be “trued-up” in any given year and are directly (rather than indirectly) charged to customers on a fixed per-customer basis.

Q. HOW ARE THESE TWO REVENUE NEUTRALITY MECHANISMS RELATED TO QUESTAR’S CET?

A. The Company's CET is a form of full revenue decoupling where actual revenues are trued-up to some fixed benchmark. Customers would still be billed on a volumetric basis, but these volumetric rates would be “trued-up” periodically based upon the actual revenues collected per customer. In effect, the revenue decoupling process makes the Company indifferent between collecting DNG revenues through fixed or variable charges. The process is similar in many ways to loading total DNG revenue requirements into a fixed charge since customers are no longer able to avoid any portion of the DNG revenue requirement through reduced usage.

Q. CAN YOU PROVIDE AN EXAMPLE?

A. Yes, CCS Exhibit 1.1 shows how the CET works. The first step, conducted in an earlier phase of this proceeding, was to set a base year (or test year) DNG revenue per customer level. For illustration purposes, the test year total DNG revenue per customer is \$250. The second step is to allocate the total charge per customer on a monthly basis over the course of a “typical” year which is provided in the second box of this exhibit. Each month the actual revenues collected per customer (from the per unit, or per Mcf charge) are compared to allowed monthly amounts and are either credited or debited to a balancing

account. The balancing account is “trued-up” at every six months, and the resulting amount is applied to the volumetric charge on customers’ bills. The new volumetric charge resulting from the example is provided in the third box. This represents the difference for the month of January alone. The same procedure would need to be replicated for the remaining 11 months of the year, and the accrual summed to a total amount.

Q. IS REVENUE NEUTRALITY PRESENTLY UNDERGOING AN ACTIVE POLICY DEBATE?

A. Yes. Revenue neutrality is being actively debated before various state legislatures and state regulatory commissions. For some groups, revenue neutrality is seen as a must-have for the promotion of energy efficiency. Other groups, particularly consumer groups, are very concerned about the adoption of these types of policy mechanisms and the implications they may have for customer bills. Two prominent consumer groups have recently either opposed or had members expressing serious concerns regarding revenue neutrality mechanisms. These groups include the Electric Consumers Resource Council (“ELCON”) and the National Association of State Utility Consumer Advocates (“NASUCA”).

Q. WHAT POSITION HAS ELCON TAKEN RECENTLY ON REVENUE DECOUPLING?

A. ELCON, an advocacy group comprised of a large number of major industrial customers of electricity, has recently issued both a position statement and White Paper that is adamantly opposed to revenue decoupling: a position

similar to that taken by most industrial customers in the early 1990s when revenue neutrality mechanisms were initially debated. The White Paper issued by ELCON noted many flaws with this policy mechanism including:

- (1) Decoupling promotes mediocrity in the management of a utility;
- (2) Decoupling shifts significant business risk from shareholders to consumers with only limited opportunities for net increases in consumer benefits;
- (3) Decoupling eliminates a utility's financial incentive to support economic development within its franchise area;
- (4) Decoupling tends to address "Lost Revenues" and not the real issue which is "lost profits;"
- (5) Sending appropriate price signals is the most important step in promoting energy efficiency;
- (6) Third party, independent delivery of energy efficiency services is a more effective means of addressing incentives.

Q. WHO DOES NASUCA REPRESENT?

A. NASUCA represents the various state-funded attorneys general, consumer counsels, and consumer advocate agencies charged with representing the interests of small customers in utility proceedings.

Q. HAS NASUCA ISSUED A FORMAL POSITION STATEMENT OR RESOLUTION ON REVENUE DECOUPLING?

A. Decoupling is a topic being closely watched by various NASUCA Committees (consumer protection, gas and electric) and will be actively

discussed in Denver this summer. Most of the member states of NASUCA that have been engaged in revenue neutrality proceedings at the state level have opposed most forms of revenue neutrality, including revenue decoupling.

Q. WHAT IS THE CURRENT STATUS OF REVENUE NEUTRALITY PROPOSALS?

A. Various states have taken action on revenue decoupling and SFV rate design proposals for both electric and gas utilities. CCS Exhibit 1.2 and CCS Exhibit 1.3 provide maps showing the states that have considered each of these policy mechanisms. While many states have considered both forms of revenue neutrality, very few have adopted SFV, while only slightly more have embraced revenue decoupling.

Q. HOW MANY STATES HAVE EITHER ADOPTED OR ARE CURRENTLY CONSIDERING THE ADOPTION OF REVENUE DECOUPLING MECHANISMS?

A. CCS Exhibit 1.2 shows the recent activity on revenue decoupling for electric and gas utilities across the U.S. Currently, there are ten states that have adopted revenue decoupling as either a permanent or pilot mechanism for electric and/or gas utilities. These states include North Carolina, Indiana, Ohio, New Jersey, Maryland, Vermont, California, Oregon, Idaho, and Utah. Another three states (Minnesota, Colorado, and Nebraska) are currently considering revenue decoupling.

Q. HAVE ANY STATES REJECTED REVENUE DECOUPLING PROPOSALS?

389 A. Yes, revenue decoupling proposals for gas or electric utilities have either
390 been rejected by state commissions or withdrawn by utilities in eleven states,
391 including Washington, Arizona, Nevada, Kansas, Arkansas, Wisconsin, New
392 York, Delaware, Michigan, Iowa, and Connecticut. All of these states except for
393 Arkansas have an active DSM program in place for the utility whose revenue
394 decoupling proposal was either rejected or withdrawn. Most state commissions
395 rejected revenue decoupling on a variety of sound public policy reasons that are
396 consistent with the position taken by the Committee in this proceeding. Further,
397 many of these state commissions were not convinced that revenue decoupling
398 was necessary for the adoption of cost-effective DSM programs. Appendix 2
399 provides a summary of the state decisions rejecting revenue decoupling or states
400 in which revenue decoupling proposals were withdrawn.

401 **Q. IS REVENUE DECOUPLING REQUIRED FOR THE ADOPTION OF**
402 **ENERGY EFFICIENCY?**

403 A. No. CCS Exhibit 1.2 clearly shows there are a large number of electric
404 and gas utilities operating in ten states that have mature and extensive energy
405 efficiency programs without a revenue decoupling mechanism. Some 21 states,
406 accounting for around 47 percent of all U.S. residential electric and gas
407 customers, have found a way to promote energy efficiency under more traditional
408 ratemaking approaches.

409 **Q. HAVE THE STATES RECENTLY ADOPTING REVENUE DECOUPLING**
410 **SEEN CONSIDERABLE DSM INITIATIVES BY THEIR REGULATED**
411 **UTILITIES?**

412 A. Some have, while others have not. In Utah, Questar has clearly made a
413 significant effort in developing DSM programs on an accelerated pace. However,
414 in other states, the results are a little more mixed. For example, revenue
415 decoupling was adopted in Ohio and Indiana in the latter half of 2006, but utilities
416 have been slow to respond with new DSM programs. North Carolina adopted
417 revenue decoupling about 18 months ago and ratepayers are being asked to
418 cover a \$50 million revenue decoupling balancing account shortfall with what
419 appears to be limited access to DSM programs.

420 **Q. WHAT HAS BEEN THE PROCEDURAL CONTEXT IN WHICH**
421 **REVENUE NEUTRALITY PROPOSALS HAVE BEEN CONSIDERED IN**
422 **OTHER STATES?**

423 A. Over the past three years, revenue neutrality programs have been
424 considered in at least 15 rate case proceedings rather than a stand-alone docket
425 like the one in Utah. This is an important distinction since a rate case gives a
426 regulatory commission, as well as other parties, a wide range of ratemaking tools
427 and policy options to address structural and programmatic changes in demand
428 that may be affecting a utility's earnings.

429 **Q. CAN YOU PROVIDE AN EXAMPLE OF HOW A RATE CASE WOULD**
430 **BE A BETTER VENUE TO CONSIDER MANY OF THE ISSUES RAISED BY**
431 **THE COMPANY?**

432 A. Yes, if the declining use per customer trend is significant and quantifiable,
433 then there are approaches such as repression adjustments to test year billing
434 determinants that can account for the structural changes in demand. Examining

these issues outside of a general rate case confines the potential remedies to an “all-or-nothing” solution: revenue decoupling or nothing. Unfortunately, this is very limiting, and I will discuss some of the other options at the Commission’s disposal (most of which would be in the context of a rate case) in Section VII of my testimony.

V. MAINTAINING THE CET WOULD NOT BE IN THE PUBLIC INTEREST AND SHOULD BE DISCONTINUED

Q. IS IT CLEAR THAT A SIGNIFICANT UTILITY DISINCENTIVE TO PROMOTE ENERGY EFFICIENCY REALLY EXISTS?

A. No. It is not clear that a significant utility disincentive exists in promoting least-cost efficiency resources because often the net results of utility-sponsored DSM are varied. For some utilities, promoting energy efficiency can be a means of offering a value-added service that reduces customer bills, increases customer satisfaction, increases planning flexibility, and reduces the overall long run cost of service. Further, utilities should have a very strong incentive to develop least cost resources through traditional regulation and their opportunity to earn a fair rate of return on their investments.

Q. ARE THERE ANY OTHER REASONS WHY DSM CAN IMPACT UTILITY PROFITABILITY DIFFERENTLY?

A. Yes, it is difficult to assign any generalized DSM-specific impact on utility profitability since the net result is influenced by a range of factors that can include the types of programs a utility promotes, the forecasted changes in its customer base and its costs of serving those customers, the certainty with which it has

estimated potential customer savings, the costs and scope of the energy efficiency programs it is promoting, and other incentives (both positive and negative) that have been offered by its state utility regulators.

Q. IN LOOKING AT OTHER GAS UTILITIES, IS IT THE CASE THAT REVENUE DECOUPLING IS NEEDED IN ORDER TO BE SUCCESSFUL AT PROMOTING DSM?

A. No, that does not appear to be the case. CCS Exhibit 1.4 is a modified version of an exhibit presented by one of the Joint Applicants in the original filing (Exhibit HG-2) examining DSM programs, costs, and savings for 2004. Of the ten gas utilities listed, only three have revenue decoupling. Interestingly enough, the top two gas utilities on the list in terms of total program spending as a percent of retail revenues (Vermont Gas and Aquila) do not have revenue decoupling. However, these two utilities outspend as a share of revenues, the three utilities that have revenue decoupling. In terms of performance, Vermont Gas and Keyspan were able to attain benefit-cost ratios of 5.6 and 3.0, respectively, without any type of revenue decoupling program.

Q. LOOKING AT THIS ISSUE MORE BROADLY, IS IT THE CASE THAT MOST ELECTRIC AND GAS UTILITIES PROMOTING DSM HAVE REVENUE DECOUPLING MECHANISMS?

A. No. Exhibit CCS Exhibit 1.2, discussed earlier, also shows that there are several states that require the use of energy efficiency programs yet have no revenue decoupling mechanisms. Currently, there are ten states that have energy efficiency programs but do not have revenue decoupling mechanisms.

Further, all of the 11 states which recently rejected or withdrew revenue decoupling have programs to support energy efficiency. In total, there are some 21 states which support energy efficiency without revenue decoupling.

Q. DOES REVENUE DECOUPLING HAVE ANY NEGATIVE IMPLICATIONS FOR RATEPAYERS?

A. Yes, revenue neutrality proposals can have a number of negative implications for ratepayers including shifting a wide range of traditional business risks away from shareholders and towards ratepayers. This includes risks associated with changes in the economy, changes in commodity prices, and in some instances, changes in weather. Those proposals that fail to account for this risk shifting, through some type of adjustment mechanism, can impose a cost onto ratepayers without any corresponding benefit.

Q. HOW DO TYPICAL REVENUE NEUTRALITY PROPOSALS SHIFT RISK AWAY FROM UTILITIES AND TOWARDS CUSTOMERS?

A. Risk is shifted to customers through the revenue per customer true-up mechanism. This mechanism provides utilities with a **guaranteed** revenue per customer amount. Current regulatory approaches only give utilities an **opportunity** to earn typical revenues, but do not guarantee that recovery. Under the current rate design, customers have the opportunity to avoid a portion of their distribution non-gas charges if they conserve energy (lower consumption), install energy efficient appliances, or take other energy efficiency steps. This will not be the case under the CET which essentially requires customers to reimburse the utility for any savings that result from customers' conservation efforts. .

Q. WHAT TYPES OF FACTORS IMPACT REVENUE RECOVERY UNDER TRADITIONAL REGULATORY APPROACHES?

A. A number of factors can influence sales including economic conditions, gas commodity prices, weather, and other unanticipated events that impact usage. Under traditional regulation, these risks are usually borne by the utility, not by ratepayers. Under the Company's proposals, these risks are entirely shifted to ratepayers since there is no means for customers to reduce distribution charges by reducing usage in the face of economic recessions, higher prices, warmer weather, and other factors.

Q. HOW ARE ECONOMIC RISKS SHIFTED TO RATEPAYERS?

A. If revenues decline due to a contraction in the economy, customers will be required to make the utility whole for those revenue shortfalls. Decreases in sales associated with economic downturns have nothing to do with energy efficiency or a DSM program promoted by the Company. Instead, they are the natural reaction of households trying to reduce their expenditures during difficult economic times. Under the CET, customers will be required to make a utility whole for possible losses during economic downturns, whereas under traditional regulation, this would not have been the case.

Q. ARE THERE ANY REAL-WORLD EXAMPLES OF HOW REVENUE NEUTRALITY PROGRAMS CREATED SERIOUS PROBLEMS DURING AN ECONOMIC CONTRACTION?

A. Yes, one of the more widely-recognized failures of revenue decoupling occurred in Maine during the early 1990s. The program, known as "ERAM"

527 (“Electric Revenue Adjustment Mechanism”), was put into place for a three-year
528 trial period to encourage Central Maine Power (“CMP”) to promote DSM. The
529 ERAM had no adjustments for changes in regional activity. The adoption of the
530 ERAM coincided with a recession that resulted in lower sales levels and
531 substantial revenue deferrals. CMP was entitled to recover these deferrals under
532 the provisions of the ERAM mechanism, which by the end of 1992 reached \$52
533 million. Only a very small portion of this amount was attributed to CMP’s
534 conservation efforts as most of the deferral resulted from the economic
535 recession. The ERAM was viewed by many as a mechanism that shielded CMP
536 from the economic impact of the recession rather than furthering the intended
537 conservation incentives. CMP’s ERAM was terminated on November 30, 1993.¹

538 **Q. HOW IS COMMODITY PRICE RISK SHIFTED TO CUSTOMERS?**

539 A. When gas commodity prices increase, customers tend to reduce
540 consumption. In fact, it is likely that some portion of the decreases in use per
541 customer highlighted throughout the Company’s original application are the result
542 of price-induced reductions in consumption created by recent increases in natural
543 gas prices. Since the Company did not have DSM programs in place prior to
544 January 2007, these historic use per customer reductions are clearly based upon
545 actions taken by customers, not Questar. While the Company has been active in
546 developing and rolling out its DSM programs over the past year, it will take some
547 time before participation goals (savings) are realized. Thus, any balances

¹*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

(positive or negative) associated with the current CET are clearly not associated with DSM programs at this time.

Q. DO YOU AGREE WITH THE STATEMENT THAT REJECTING REVENUE NEUTRALITY IS COMPARABLE TO DENYING A UTILITY THE OPPORTUNITY TO EARN ITS ALLOWED REVENUES?

A. No. The fact that the utility exactly recovers its allowed revenues until its next rate case is not the problem. The issue is that a very large portion of the risk associated with recovering those revenues has been shifted entirely onto ratepayers without any corresponding benefit. If this proposal is, in fact, a good thing for the Company, then some type of benefit should be passed long to its customers for absorbing this risk. Further, the benefit needs to be more than just the DSM program offerings being provided by the Company. These programs and their potential benefits, while important, are limited. Even under the Company's best estimates, their DSM programs will only provide direct benefits to a small share of their residential and small commercial customer base while the CET impacts all GS-1 and GSS customers.

Q. HAVE ADJUSTMENTS TO A UTILITY'S ALLOWED RATE OF RETURN FROM REVENUE NEUTRALITY PROPOSALS BEEN RECOGNIZED IN OTHER UTILITY PROCEEDINGS?

A. Yes. CCS Exhibit 1.5 shows information from various past regulatory proceedings that have recognized cost of capital adjustments due to revenue neutrality programs that change the risk profiles of regulated utilities. Many of these adjustments have actually been proposed, or developed, by utilities.

571 These adjustments range from 25 to 100 basis points on a utility's allowed ROE.
572 To date, most of these adjustments have been offered in proposal form and, with
573 the limited exception of the FERC proceedings, have not been used to offset the
574 risk-shifting nature of the various revenue neutrality mechanisms. In fact,
575 revenue neutrality was rejected in most of the states where these risk-adjustment
576 proposals were offered. Recently, the Citizens Utilities Regulatory Board in
577 Kansas requested a 110 basis point reduction on the allowed ROE. This
578 proceeding recently settled and the revenue neutrality proposals were withdrawn
579 for later consideration in a generic docket. In Vermont, Green Mountain Power
580 agreed to a 50 basis point reduction and noted that its Alternative Regulation
581 Plan "has the effect of shifting risk associated with varying power costs to
582 ratepayers; in recognition of this risk shift, the Plan provides a lower return on
583 equity."²

584 **Q. DO YOU THINK THAT MAKING THESE ADJUSTMENTS WOULD BE**
585 **APPROPRIATE AT THIS TIME?**

586 A. No, for at least two reasons. First, any adjustments to the Company's
587 ROE should be done within the context of a rate case. In fact, over the past
588 several years, most revenue neutrality proposals (decoupling and SFV) have
589 been proposed within the context of a rate case allowing regulators to fully
590 evaluate all adjustment mechanisms that may, or may not, be needed to facilitate
591 energy efficiency. These potential adjustment mechanisms are not limited to

² Petition of Green Mountain Power Corporation for approval of an alternative-regulation plan, Docket No. 7175; Docket No. 7176, Vermont Public Service Board, December 22, 2006, Order Entered.

revenue decoupling or SFV alone, and can range from combinations of revenue neutrality and a utility's allowed ROE, to partial revenue decoupling, to simply changing test year billing determinants, to rate design changes, to no changes at all. As noted earlier, the current CET proceeding does not lend itself well to many of these types of adjustments since this is not a rate case where a broad range of other options would be candidates for consideration. Second, the adjustments provided in CCS Exhibit 1.5 are specific to the companies in those proceedings, and while these are important in providing insight into the range of potential ROE adjustments associated with revenue neutrality, any adjustment for Questar needs to be evaluated relative to its specific financial circumstances.

Q. IF NO ADJUSTMENTS ARE MADE TO OFFSET THE RISK-SHIFTING NATURE OF THE CET, CAN MAINTAINING THIS MECHANISM RESULT IN FAIR, JUST, AND REASONABLE RATES?

A. No. The Company's CET shifts a significant amount of risk to ratepayers. These risks include potential changes in price, the economy, and other factors like greater economy-wide energy efficiency. However, there is no corresponding offset in rates to compensate ratepayers for this shift. Granted, the current monthly balances associated with the CET have been mostly offsetting. But relatively low net-adjustments are more a function of current circumstances in the market as opposed to a removal of these risks. It could very well be the case that circumstances could shift (unfavorably) and change the overall nature of the balances accruing in the CET balancing account. Ratepayers would be on-call to cover those shortfalls should this negative market

615 realization materialize. Thus, maintaining the CET, while failing to recognize the
616 risk-shifting inherent in this mechanism, results in rates that by definition are not
617 fair, just, and reasonable and allows the utility to claw into the very monopoly
618 profits that regulation is intended to control.

619 **Q. DO YOU THINK THE FINANCIAL COMMUNITY RECOGNIZES THE**
620 **RISK SHIFTING NATURE OF REVENUE NEUTRALITY MECHANISMS?**

621 A. Yes, as well as a number of other favored, risk-shifting programs that can,
622 depending upon the state, include the adoption of gas recovery clauses, weather
623 normalization clauses, shorter weather normalization periods, and pass-through
624 recovery of LAUF and uncollectibles expense. Revenue neutrality, in the form of
625 revenue decoupling or SFV rate designs, however, appears to be the most
626 popular regulatory mechanism with many of these financial analysts (with the
627 exception of the few utilities that do not have GCRs). These analysts see
628 revenue neutrality mechanisms as being beneficial to shareholders by reducing
629 overall risk. Many financial analysts are starting to preference the ratings and
630 categorizations of those companies that have such policies in place.

631 **Q. DO YOU HAVE ANY EXAMPLES?**

632 A. Yes, Moody's Investor Service ("Moody's"), in a June 2005 Special
633 Comment on natural gas utilities, noted:

634 "Moody's believes that having utility rate designs that
635 compensate the gas LDC for variations in conservation as with
636 variations in weather would serve to stabilize the utility's credit
637 metrics and credit ratings."³

³ *Special Comment: Impact of Conservation on Gas Margins and Financial Stability in the Gas LDC Sector*, Moody's Investors Services, June, 2005: 8.

Further, Moody's indicated that revenue decoupling can impact the business risk categorization under which utilities are judged by Standard and Poor's. This categorization, based upon business risk profiles, includes a measure for utilities that face supply and volumetric risk. Those with high risk are in the higher categories (highest risk category is 10), while those utilities that face lower risks by having adjustment clauses, are moved to lower levels. NW Natural, a gas distribution utility in Oregon that has both a GCR and decoupling mechanism, was able to lower its rank to 1, the lowest level category. Moody's recently reiterated the strong benefits revenue decoupling would provide in maintaining shareholder value. Such a mechanism will maintain strong credit metrics and improve credit ratings relative to utilities that do not have such mechanisms since revenue decoupling eliminates shareholder exposure to risk and volatility from price and climate changes.⁴

Q. CAN REVENUE DECOUPLING LEAD TO POTENTIAL COST INEFFICIENCIES?

A. Yes. Utilities, while regulated, are similar to other competitive firms in their goals of maximizing profits. These profits are a function of revenues and costs, both of which can reflect a certain degree of uncertainty. However, of the two, revenues can be more uncertain since, as noted earlier, they can be impacted by a wide range of factors beyond a utility's control like changes in commodity prices, changes in the economy, and changes in the weather, to name a few. Costs normally have more certainty and are typically within a utility's control.

⁴ *Special Comment: Local Gas Distribution Companies: Update on Revenue Decoupling and Implications for Credit Ratings*, Moody's Investor Services, June 2006.

Q. HOW DOES THE TRADITIONAL RATEMAKING PROCESS GIVE UTILITIES INCENTIVES TO REDUCE COSTS?

A. The regulatory lag inherent in the traditional ratemaking process gives utilities strong incentives to reduce costs, and potentially increase earnings, during periods between rate cases. In many instances, this will require effective efforts at reducing costs since, as noted earlier, revenues are much more uncertain. Active cost reducing efforts have the ability to compensate for unexpected changes (decreases) in revenues, thereby increasing profitability. However, under most revenue neutrality mechanisms, one-half of this equation, revenues is now known. Revenue decoupling eliminates revenue uncertainty (assuming a constant level of customers), which in turn can dampen efficiency incentives.

Q. GIVEN THE COMPANY'S RECENT FINANCIAL PERFORMANCE, IS THE CET NECESSARY?

A. No. From a financial perspective, maintaining the CET is unnecessary for at least 4 reasons:

- (1) The Company has been able to maintain relatively strong earnings despite decreases in use per customer.
- (2) The CET appears to have less to do with addressing revenue losses from energy efficiency than assuring revenue certainty. The order of magnitude of the potential losses resulting from DSM programs are small relative to the potential changes resulting from use per customer decreases.

(3) Revenue growth associated with adding new customers more than offsets revenue losses from both DSM and use per customer changes.

(4) As noted earlier in the Elcon White Paper opposing revenue decoupling, the real issue is profitability, not revenues. The real potential drag in overall Company profitability appears to have less to do with revenue losses and more to do with increases in incremental investment (rate base) per customer.

VI. DIRECT RATEPAYER BENEFITS OF THE CET ARE SMALL

Q. HOW SIGNIFICANT ARE THE COMPANY'S ANTICIPATED DSM SAVINGS?

A. CCS Exhibit 1.6 provides an overview of the anticipated level of natural gas savings (in Dth) from the Company's DSM programs over the three year pilot period. Total savings for each year increases from a level of 163,501 decatherms ("Dth") in the first year of the program to a high of 189,731 Dth by the third and last year of the pilot program. Two of these DSM programs account for 72 percent to 84 percent of the total anticipated DSM savings.

Q. HOW DO THESE COMPARE TO OVERALL SALES LEVELS?

A. The right hand side of the chart shows that these savings levels are very small shares of the Company's overall total sales. Using the Company's historic rate of sales growth (2.0 percent), shows that DSM savings over the next three years will only comprise between 0.184 percent to 0.205 percent of overall sales.

Q. HOW DO THESE SAVINGS PERCENTS COMPARE TO THE PROGRAMS LISTED BY OTHER LEADING GAS UTILITIES?

A. These levels of savings are low relative to most gas utilities that are often referred to as leaders in gas-use energy efficiency. CCS Exhibit 1.4, discussed earlier, shows that most of the leading gas utilities are achieving a level of savings that range from a low of 0.1 to a high of 1.0 percent. The average for the ten utility sample is a savings level of 0.5 percent.

Q. ARE YOU SUGGESTING THE COMPANY ISN'T DOING A GOOD JOB PROMOTING ITS DSM PROGRAMS?

A. Not at all. In fact, the Company has done a good job in developing and promoting its DSM plan to date. However, it appears from the savings estimates generated by Questar and its consultants that the cost-effective savings potential is less in Questar's service territory compared to other parts of the country for a variety of different reasons, many of which may have nothing to do with the Company's current efforts.

Q. WHAT ABOUT THE ANTICIPATED PARTICIPATION LEVELS?

A. CCS Exhibit 1.7 provides the anticipated participation for each of the Company's current DSM programs. As seen from the exhibit, most programs have participation rates that are far less than the majority of the customers in the GS-1 class. However, all residential and small commercial customers will be required to participate in the CET, to the benefit of the few that are participating in the Company's DSM programs. Again, this is not to suggest that the Company

is not doing a commendable job in promoting its DSM programs. It does suggest however, that the CET is too broadly applied.

Q. HOW LARGE ARE THE ANTICIPATED LOST REVENUES?

A. CCS Exhibit 1.8 provides the annual anticipated lost DNG revenues associated with the Company's DSM programs. These lost revenues, over a three-year period, range from a low of \$288,537 to a high of \$334,826. In each year, the amount of revenue lost from the promotion of cost-effective DSM is less than one-half of one percent of the Company's total GS-1 revenues.

Q. HAVE YOU ATTEMPTED TO ESTIMATE THE IMPACT THAT THE COMPANY'S DSM PROGRAMS WILL HAVE ON ITS FINANCIAL RESULTS?

A. Yes, CCS Exhibit 1.9 provides an analysis of the potential impact that the Company's current DSM programs may have on its financial results over the next three years. Overall, the Company could see a cumulative total revenue loss of some \$1.8 million associated with its DSM programs over the next three years. In addition, if recent trends continue, the Company could see a cumulative revenue loss of \$9.3 million decrease associated with a decrease in use per customer – an amount far in excess of the sales decreases resulting from its DSM programs. Over the same period, however, the Company could see a \$19.6 million cumulative increase in revenues due to customer growth. The net impact of these usages changes is \$5.2 million, resulting in a positive 1.61 percent impact on ROE. Thus, the Company may continue to see a net positive increase in its financial performance despite its promotion of DSM.

749 **Q. WHAT IF THE COMPANY'S DSM PROGRAMS PERFORM BETTER**
750 **THAN EXPECTED?**

751 A. The Company would have to attain DSM participation levels (or savings
752 per participant levels) well in excess of its current expectations in order for its
753 promotion of DSM to have a meaningful impact on its financial performance.
754 Currently, the Company expects to lose an estimated \$1.76 in lost revenues for
755 every one Dth in anticipated energy efficiency savings. The analysis in CCS
756 Exhibit 1.9 shows that at current expectations, the Company has \$5.2 million in a
757 positive earnings "buffer" that would have to erode before it became financially
758 challenged from promoting DSM. Given the lost revenue/DSM savings
759 relationship above, it would take an additional 3.0 million Dth in savings to bring
760 the Company to a point where DSM promotion stalls the growth in its achieved
761 ROE. This is a savings level that is some 160 percent higher than current cost-
762 effective savings expectations.

763 **Q. DO YOU THINK THIS LEVEL OF LOST REVENUES JUSTIFIES**
764 **MAINTAINING THE CET?**

765 A. No, the financial implications of promoting DSM appear to be small and it
766 would appear that a more important benefit the Company and its shareholders
767 get from the CET is associated with revenue insurance on potential changes in
768 use per customer and not the promotion of DSM. As I will discuss later in my
769 testimony, if the change in use per customer is the real concern, there are other,
770 more specific ratemaking tools to address this problem that are preferable to the
771 use of an overly-broad CET.

772 **Q. WHAT IS THE RELATIONSHIP BETWEEN TOTAL USAGE, USE PER**
773 **CUSTOMER, AND NET EARNINGS?**

774 A. In the earlier phase of this proceeding, I provided an exhibit in my
775 supplemental rebuttal testimony outlining the relationship between earnings and
776 changes in sales and revenue. The relationship has been replicated in CCS
777 Exhibit 1.10. This exhibit shows that changes in total usage are a function of: (1)
778 the change in usage per customer associated with existing customers and (2) the
779 new usage associated with customer growth. If usage increases resulting from
780 customer growth outpace the usage decrease associated with reduced usage
781 per customer (from existing customers), then total usage will increase. The
782 inverse would occur if usage from customer growth was less than the total
783 decreases created by reduced use per customer. If prices and costs are held
784 constant, then earnings will continue to increase if new customer-related usage
785 growth outpaces the decrease in use per customer for existing customers. The
786 inverse would occur if new customer-created usage was less than the decreases
787 in use per customer for existing customers; again, holding other factors constant.
788 Thus, the impact that decreases in use per customer have on earnings growth
789 can be offset for a utility serving a growing service territory. Utilities that serve
790 very slow growing service territories could see earnings attrition if usage per
791 customer falls. All of these relationships are based upon the premise that other
792 factors are held constant.

793 **Q. HAVE YOU UPDATED YOUR ESTIMATE OF THE CHANGES IN NET**
794 **REVENUES FROM CHANGES IN USE PER CUSTOMER BASED ON THE**
795 **COMPANY'S ACTUAL DATA?**

796 A. Yes. I have presented a series of different exhibits that highlight some of
797 these relationships from information included in the Company's Results of
798 Operations. CCS Exhibit 1.11 shows the offsetting impacts on total usage
799 created by (1) changes in use per customer and (2) changes associated with
800 customer growth. Between 2001 and 2002, the Company saw a net GS1 sales
801 decrease by 37,156 Dth. GS-1 customers during that period grew by 2.6
802 percent, or by some 17,976 customers. Usage decreases associated with
803 decreases in use per customer were of a comparable percent (2.6 percent), or
804 from 118.97 Dth/customer to 115.84 Dth/customer. As seen from the last three
805 columns, the impact on total consumption was close to offsetting between the
806 two impacts. Total usage reductions resulting from decreased use per customer
807 were estimated to be around 2,119,521 Dth, while increased usage from new
808 customers is estimated to be 2,082,365 Dth. The net change (subtracting the
809 two) was a decrease of 37,156 Dth.

810 **Q. HOW HAVE USAGE TRENDS CHANGED IN LATER YEARS?**

811 A. There have been several years of both increases and decreases in total
812 usage. Between 2002-2003, both use per customer and usage associated with
813 new customers increased. Increases in annual use per customer is estimated to
814 have contributed 2,126,113 Dth to overall sales. The increase in use from new
815 customer growth was 3,401,338 Dth. The total annual change in sales that year

is the sum of these two impacts or 5,527,451 Dth. Other years have seen comparable movements; in the most recent full year, use per customer reductions contributed to a decrease of 1,148,163 Dth, while increased usage associated with customer growth was 2,094,399 Dth, resulting in a net positive change of 946,235 Dth. Over the past five years, there have been two years of net decreases in usage amounting to 878,484 Dth. There have also been three years of substantial net increases in usage accounting for 9,096,013 Dth. The net period change has been an increase in usage (net of decreases created by use per customer declines) of 8,217,528 Dth. In other words, the Company has seen total usage increase of over 8 million Dth despite the decrease in average use per customer.

Q. HAVE YOU UPDATED YOUR ANALYSIS TO EXAMINE THE CHANGES IN REVENUE ASSOCIATED WITH THESE USAGE CHANGES?

A. Yes, CCS Exhibit 1.12 presents a comparable analysis on a revenue basis. Two different columns have been provided that show the estimated changes in revenues associated with a decrease in use per customer versus the increase in revenues associated with changes in customer growth. Between 2001 and 2002, I have estimated that revenues decreased by \$2.8 million dollars due to decreased usage per customer. There was, however an estimated revenue increase due to customer growth for that period of \$4.9 million, resulting in a net revenue increase of \$2.1 million. In the subsequent year, it is estimated that revenues increased for both impacts since average usage per customer and

customer growth were both positive and significant (net positive change of \$17.8 million).

Q. HAVE YOU ATTEMPTED TO ESTIMATE THE FINANCIAL IMPACT OF THE RECENT CHANGES IN USAGE?

A. Yes. CCS Exhibit 1.13 provides that information. The exhibit consists of three pages: (1) a summary page; (2) detailed calculations on the estimated financial impact of changes in use per customer; and (3) detailed calculations on the estimated financial impact of changes from customer growth. The first summary page of the exhibit shows that for the better part of the five year period, the positive financial contributions of customer growth exceeded the negative implications of decreases in use per customer. The only exception was in 2003 when positive use per customer is estimated to have actually contributed more to the overall financial results than the increase in customer growth. The information at the bottom of the summary table provides comparable information for the return on equity ("ROE").

Q. IF USAGE PER CUSTOMER DOES NOT APPEAR TO BE DRAGGING DOWN THE COMPANY'S FINANCIAL PERFORMANCE, WHERE IS THE PROBLEM?

A. The problem appears to be associated with the cost of providing service to new customers. Page 1 of CCS Exhibit 1.13 shows that changes in rate base have the largest negative impact on the Company's achieved ROR – not changes in usage. CCS Exhibit 1.14 shows the Company's recent investment trends on an average and incremental basis. The bottom two rows are the more

informative. Average net utility plant in service per customer ranges between \$835 to \$934 per customer. However, the incremental net utility plant cost per change in customer is significantly higher at an average of around \$1,430 for the past several years.

Q. WHAT CONCLUSIONS DO YOU DRAW FROM THIS ANALYSIS?

A. It appears that the real challenge the Company faces is associated with its average incremental investment costs relative to the revenues gained from new customers. This has nothing to do with DSM, and appears to have less to do with decreasing use per customer (for existing customers), or usage in general. The problem appears to be one that is more cost-related and associated with making new capital investments. These are issues that are more appropriately addressed in the traditional ratemaking areas of cost recovery and rate design, rather than through a revenue decoupling mechanism like the CET. Trying to use decoupling as a means of correcting this problem is akin to creating an attrition adjustment. This would be inconsistent with the purpose of decoupling as it has been adopted in other states.

Q. DOES THIS DECOMPOSITION OF USAGE AND CUSTOMER GROWTH IMPACTS HAVE ANY BEARING ON THE CONSTRUCTION OF THE CET?

A. Yes. The common complaint that many LDCs express is that use per customer has been falling over recent years and that rates, set in the past, fail to catch up with the differences between test (or base) year use per customer and actual use per customer. In order to remedy this problem, decoupling has been proposed to “true-up” revenues to the test year in order to give LDCs the

884 opportunity to earn their authorized rate of return. In order to make an LDC
885 whole relative to the test year upon which its rates are based, a decoupling
886 mechanism should be examining the difference between actual and test year
887 revenues per customer relative to the test year customer level upon which costs
888 and revenues are based. However, the current formulation of the CET, like many
889 LDC decoupling proposals, adjust current period revenues for more than just
890 changes in use per customer from the test year, and also allows for revenue
891 recovery associated with customer growth.

892 **Q. CAN YOU PLEASE EXPLAIN THIS CONCERN IN GREATER DETAIL?**

893 A. Yes. The left hand side of CCS Exhibit 1.15 shows an example of the
894 Company's current CET methodology that is comprised of three important steps:

- 895 (1) determining the test year use per customer;
- 896 (2) estimating the difference between test (or base) year revenue per
897 customer and actual revenue per customer;
- 898 (3) Multiplying the difference by the actual (new) level of customers.

899 The third step in this calculation is the one to note since it allows for the collection
900 of revenues based upon customer growth.

901 **Q. HOW COULD THIS BE CHANGED TO BE MORE CONSISTENT WITH**
902 **THE TEST YEAR UPON WHICH RATES ARE SET?**

903 A. Instead of multiplying differences in actual from historic revenue per
904 customer by a new level of customers (step 3 discussed earlier), this difference
905 should instead be multiplied by the customers included in the base year. An
906 example of this calculation has been provided on the right hand side of CCS

Exhibit 1.15 and shows that the CET accrual account using this methodology would be approximately \$228,100 less than the current method of calculation for that given monthly example.

VII. ALTERNATIVE REMEDIES FOR DEALING WITH ENERGY EFFICIENCY DISINCENTIVES

Q. ARE THERE ANY OTHER POTENTIAL REGULATORY MECHANISMS FOR ADDRESSING DSM SALES LOSSES?

A. Yes. One of the more common regulatory mechanisms for dealing with sales losses associated with DSM implementation has been what is referred to as a lost revenue adjustment (“LRA”) mechanism. Under this approach, a utility’s ability to recovery lost revenues is based upon actual savings which result from its DSM programs. For instance, if a gas utility were promoting a Energy Star Clothes Washer program that achieved 8,700 Dth in savings, and had an average DNG rate of \$1.75, then the lost revenues associated with the program would be \$15,225. Thus, revenue recovery is restricted to specific DSM-created changes in sales and not some broader measure of sales loss (like decoupling) that could result from a variety of factors, many of which are beyond the utility’s control.

Q. HAVE MANY STATE COMMISSIONS UTILIZED AN LRA APPROACH?

A. Yes, several regulatory commissions have utilized an LRA approach to remove the purported disincentive associated with promoting DSM. LRAs were particularly common for electric DSM programs prior to the advent of retail competition and industry restructuring. While some states still technically allow

930 LRA recovery, there are few active proceedings where utilities continued to seek
931 recovery of these lost revenues.

932 **Q. IS AN LRA MECHANISM A POPULAR REGULATORY TOOL AMONG**
933 **ENERGY EFFICIENCY ADVOCATES?**

934 A. No. LRAs are typically opposed by energy efficiency advocates for at
935 least two reasons. First, most energy efficiency advocates believe that LRA
936 mechanisms are exceptionally difficult to implement in practice because
937 sophisticated measurement and estimation is required in order to determine
938 actual DSM savings, and as a result, DSM-related lost revenues. Second, most
939 energy efficiency advocates believe LRA mechanisms do not completely remove
940 the disincentive to promote DSM because the mechanisms are too narrowly
941 focused.

942 **Q. WHY WOULD AN LRA MECHANISM BE A MORE EFFECTIVE TOOL**
943 **FOR DEALING WITH DSM-CREATED REVENUE LOSSES THAN THE CET?**

944 A. There are various reasons that support the use of an LRA:

- 945 (1) Regulatory policy and industry trends are insisting upon greater
946 accountability in measuring energy efficiency savings and the
947 adoption of an LRA would be consistent with these movements;
- 948 (2) Revenue decoupling and the CET creates a disincentive for
949 accountability and energy efficiency measurement;
- 950 (3) An LRA would increase regulatory confidence in the use of DSM;

951 (4) The greater accountability created through an LRA could have
952 important planning implications which, in turn, could reduce overall
953 ratepayer costs.

954 **Q. HISTORICALLY, WHAT APPEARS TO BE THE BIGGEST REPORTED**
955 **DIFFICULTY ASSOCIATED WITH LRA MECHANISMS?**

956 A. Lost revenues are simply the product of average utility base rates and the
957 actual savings attained by the DSM program. Since the average utility base rate
958 is regulated and known, the fundamental challenge in estimating lost revenues is
959 measuring and verifying the actual amount of savings.

960 **Q. HOW ARE LOST REVENUES RELATED TO COST-EFFECTIVENESS?**

961 A. Lost revenues are fundamentally related to overall DSM program cost-
962 effectiveness in two ways. First, since lost revenues are a function of program
963 savings, and overall program savings determine whether a program is cost-
964 effective, lost revenues are clearly linked to cost effectiveness. Second, one of
965 the cost-effectiveness tests (Rate Impact Measure or RIM test) is based on lost
966 revenues. The RIM test, which measures the cost-effectiveness of a DSM
967 program from ratepayers or non-participants perspective, is calculated as the
968 difference between total program savings less total program costs including lost
969 revenues. Thus, lost revenues are integral components of any DSM cost-
970 effectiveness filing.

971 **Q. DOES THE RELATIONSHIP BETWEEN LOST REVENUES AND COST**
972 **EFFECTIVENESS HAVE ANY BEARING ON THE MEASUREMENT**
973 **CRITICISMS ASSOCIATED WITH LRA MECHANISMS?**

A. Yes. The argument that lost revenues are difficult to measure is somewhat incompatible with cost-effectiveness findings upon which DSM program approvals are usually based. The implication is that regulatory approval of proposed DSM programs cannot really be based upon any accurate level of savings leaving a potentially large amount of unsupportable costs to be recovered in rates. Allowing a large share of unsupported DSM costs into rates would be no different than allowing a similar share of unsupported costs into rates for any other type of resource like a transmission line, power plant, or O&M expense. Allowing unsupportable costs into rates cannot result in rates being fair, just and reasonable.

Q. WHY DO YOU THINK MANY OF THESE LRA MEASUREMENTS ISSUES ARE LESS RELEVANT TODAY THAN IN THE PAST?

A. They are less relevant for a variety of reasons:

- (1) Measurability challenges were promoted well over a decade ago and the nature of the energy services business has changed significantly to include a higher level of monitoring and verification (“M&V”) of DSM savings.
- (2) The regulatory standards and requirements associated with M&V are becoming more stringent for accountability reasons.
- (3) Broader industry and public policy issues are driving M&V to higher standards and this will continue to be the case as DSM is being considered as a resource to meet utility planning requirements and

air emissions standards that are likely to be adopted in response to global climate change issues.

Q. REGARDING YOUR FIRST POINT, WHAT CHANGES IN THE ENERGY SERVICES INDUSTRY HAVE ANY BEARING ON THE LOST REVENUE MEASUREMENT ISSUE?

A. There have been a number of changes in the energy services business that have had a positive impact on measurement issues including:

- (1) Greater reliance on performance-based terms and conditions in energy service contracts;
- (2) Greater degrees of competition requiring service differentiation via performance and deliverability;
- (3) Better measurement equipment and software;
- (4) Greater experience with measurement techniques;
- (5) Specialization with some energy service companies focusing on independent M&V services; and
- (6) Expanding industry estimated to have over \$2 billion in project investment.

Q. HAVE REGULATORY STANDARDS CHANGED TO ADDRESS THESE MEASUREMENT ISSUES?

A. Yes, regulatory standards have changed in at least two ways. First, there has been greater understanding and appreciation for M&V for those utilities requesting cost recovery. Second, as will be discussed later in my testimony,

many states have moved to third party administrators which in many instances require M&V to assess the effectiveness of publicly-supported programs.

Q. ARE THERE CHANGES IN INDUSTRY AND PUBLIC POLICY THAT TEND TO INCREASE M&V REQUIREMENTS?

A. There are at least two important changes in industry and public policy that are quickly increasing M&V requirements and standards. Currently, most of these changes are associated with electric DSM, but will likely have important implications for gas DSM as well. The first change has to do with the use of DSM as a resource for planning purposes and the second change is the use of DSM as a resource in clean air market models being driven by rapidly escalating climate change concerns among policy makers.

Q. HOW DO UTILITY PLANNING ISSUES AFFECT M&V?

A. Many electric utilities, and even regional transmission organizations (“RTOs”) have historically had a difficult time accepting DSM resources for system planning purposes. At best these resources were heavily discounted. However, the challenges of building or acquiring new baseload resources have become more substantial due to climate change concerns, fuel price volatility and concerns relating to storing spent nuclear fuel. This leaves very little in the way of additional resource options with the exception of renewables and DSM. If DSM is to be used, continued efforts in M&V are going to have to occur in order to bridge the gap of confidence between regulators pushing DSM as a resource, and utility planners reluctant to use DSM for planning purposes.

**Q. HOW ARE CLIMATE CHANGES AND CLEAN AIR MARKETS DRIVING
M&V FOR DSM?**

A. Since the passage of the Clean Air Act Amendments of 1990, clean air markets, implemented through what is referred to as “cap and trade” programs have been the policy of choice for reducing air emissions. This has clearly been the case for SO₂ and NO_x, and will likely occur for future carbon regulation. Many states are already in the process of attempting to use DSM as a potential offset for carbon emissions. Moreover, several states and regions are considering mandatory DSM portfolio requirements much like renewable energy portfolio standards (“RPS”). DSM savings under such a program would likely have environmental attributes with tradable credits. Air market regulators, however, are very strict in ensuring that any resource upon which a tradable environmental attribute is based must be measurable and verifiable. This will put increasing pressure on M&V for utility DSM. If air market regulators can rely upon these DSM savings estimates for their environmental attributes, then it would seem reasonable that utility regulators could use them as a basis for lost revenue recovery as well.

**Q. ARE THERE ANY CAVEATS IN YOUR DISCUSSION ABOUT LOST
REVENUE MEASUREMENT ISSUES?**

A. Yes, this discussion assumes a certain degree of regulatory oversight and accountability. Thus, the issue is not the degree to which DSM savings can be measured as much as it to what extent the regulatory oversight process requires that they be measured, and the methods by which M&V is governed. This is one

the primary reasons why my prior testimony in this proceeding emphasized the role of M&V and stressed clearly defining this M&V process prior to the adoption of the CET.

Q. DO YOU THINK REVENUE DECOUPLING LIKE THE CET CREATES NEGATIVE INCENTIVES FOR M&V?

A. Yes. If revenue decoupling removes a utility's incentive to make sales, it is more than likely to also remove a utility's incentive to closely monitor sales losses. Under the CET, sales losses, for whatever reason, are now of no consequence to a utility.

Q. HOW DOES THE ACCOUNTABILITY ASSOCIATED WITH LOST REVENUES ENHANCE COMMISSION CONFIDENCE IN DSM?

A. An LRA directly ties a utility's incentive to DSM by tying lost revenue recovery to actual performance. As such, an LRA can be thought of as a type of performance-based regulation since it is the utility's performance that defines its ability to recover revenues associated with DSM-created sales losses. Tying a utility's incentive to accurate measurement gives the Commission, and other stakeholders, increased confidence that (1) the revenues being recovered by utilities are based upon verifiable achieved savings and (2) the costs incurred for DSM program development and implementation are tied to verifiable savings, thereby justifying ratepayers' investment in these programs.

Q. CAN THIS GREATER ACCOUNTABILITY HAVE IMPORTANT IMPLICATIONS FOR RESOURCE PLANNING AND FUTURE RATEPAYER COSTS?

1086 A. Yes since greater accountability reduces the discount to DSM as a
1087 planning resource. Greater accountability can have direct implications for
1088 ratepayer costs if it defers investment made from discounted DSM benefits.
1089 Consider as an example, a planning process that discounts DSM savings over
1090 some fixed period of time by 50 percent. Now take that same DSM program and
1091 apply a much higher degree of M&V upon its achieved savings, that reduces the
1092 overall benefit discount to 25 percent of total annual program savings. This 25
1093 percent differential represents a real capital investment that would otherwise
1094 have to be developed to meet ratepayer demand requirements that has now
1095 been either eliminated or deferred.

1096 **Q. IS AN LRA THE ONLY MECHANISM BY WHICH NEGATIVE DSM**
1097 **INCENTIVES CAN BE REMOVED FROM A UTILITY?**

1098 A. No. One alternative method being utilized by several states has been the
1099 use of a third-party administrator for the promotion and development of energy
1100 efficiency programs. These third-party administrators are independent bodies,
1101 usually housed within a state agency, and not directly associated with any
1102 specific utility company, although utilities may provide input, or serve on boards
1103 advising these administrators. While the responsibilities of these administrators
1104 can vary by state, they are usually in charge of developing, monitoring and
1105 verifying the success of DSM programs, market transformation initiatives, and in
1106 many instances, clean energy programs.

1107 **Q. WHAT ARE THE PERCEIVED BENEFITS OF THESE THIRD PARTY**
1108 **ADMINISTRATORS?**

1109 A. One of the primary benefits is having a dedicated administrator with no
1110 potential conflicts or disincentives to promote energy efficiency and clean energy
1111 technologies. There can also be the additional benefit of pooling resources,
1112 which could potentially reduce the overall cost of delivering DSM and clean
1113 energy. Having these types of activities centralized into one public agency can
1114 also reduce coordinating costs and potential redundancies across different types
1115 of electric and gas utility programs.

1116 **Q. HOW MANY STATES CURRENTLY HAVE SUCH THIRD PARTY**
1117 **ADMINISTRATORS?**

1118 A. CCS Exhibit 1.16 provides an overview of the states which currently utilize
1119 a third-party administrator for the development and promotion of DSM programs.
1120 Most of these administrators oversee both electric and natural gas efficiency
1121 programs. Several, like New Jersey, also oversee clean energy rebate programs
1122 for things like the development of solar energy as required under the state's
1123 Renewable Portfolio Standard ("RPS"). Most of these programs are funded by
1124 some type of state-wide surcharge.

1125 **VIII. ALTERNATIVE METHODS FOR DEALING WITH DECLINING USE PER**
1126 **CUSTOMER**

1127 **Q. ARE THERE ANY METHODS THAT COULD BE UTILIZED TO**
1128 **CORRECT OR ADJUST FOR USE PER CUSTOMER-RELATED CHANGES IN**
1129 **SALES?**

1130 A. Yes. There are a number of examples where the traditional regulatory
1131 ratemaking framework has reflected changes in usage resulting from exogenous

factors like rate changes and even DSM program savings. The typical mechanisms for making these adjustments have been within the context of modifications to the test year usage levels upon which a specific rate case is based. There are several examples of test-year modifications on both a historic and forecasted basis.

Q. CAN YOU PLEASE EXPLAIN THE PURPOSE OF A TEST YEAR IN THE RATEMAKING PROCESS?

A. A test year defines a set period of time, reflecting typical utility operations, upon which regulated utility rates are based. A test year can be based upon a historic period of time using historic information, adjusted for what are commonly referred to as “known and measurable changes” to revenues, expenses, and rate base. Alternatively, a test year can be based upon some future period of time provided revenues, expenses, and rate base projections are developed and adjusted in a fashion that reasonably reflects expected future utility operations.

Q. HOW WOULD A HISTORIC TEST YEAR REFLECT CHANGES IN NATURAL GAS USAGE?

A. A strict definition of a historic test year would only reflect changes in natural gas usage at that point in time. However, a test year which is allowed to reflect known and measurable changes could clearly accommodate reduced sales from DSM and could also reflect structural changes in gas use resulting from shifts in use per customer trends. For instance, it has not been uncommon in past ratemaking proceedings to estimate the potential repression or stimulation that could result from a particular rate design change. Given recent changes in

residential natural gas use, a regression estimate could be used to adjust test year billing determinants to reflect overall changes in use per customer.

Q. PRACTICALLY, HOW WOULD THIS REGRESSION ADJUSTMENT WORK?

A. The most straightforward way to make a use per customer regression adjustment would be to average the overall changes in use per customer over some fixed period of time to develop an overall adjustment factor to apply to the estimated usage levels relied on to develop rates. The challenge in developing this factor would be in determining the overall period upon which the factor would be based and any adjustments that might be needed to correct for any near-term usage trends. For instance, as I noted in my supplemental rebuttal testimony earlier in this docket, the decrease in use per customer appears to have slowed in recent years relative to historical trends. Basing an adjustment factor over a longer run use per customer trend could, therefore, overshoot the near term changes anticipated in the market.

Q. PLEASE PROVIDE AN EXAMPLE?

A. CCS Exhibit 1.17 provides an example of how a use per customer regression adjustment could be made as a known and measurable change within the context of a historic test year. Two panels are provided to the right and left of this exhibit reflecting regression adjustments based upon a three-year average and five-year average change in use per customers, respectively. While the exhibit uses Questar-specific data, both examples are presented as illustrative in nature. Row 1 in both examples lists the absolute decrease in use per customer

in the two different periods examined. The repression adjustment to test year revenues is provided on row 11 and reflects the additional amount that would need to be collected in rates if changing trends in use per customer were included in a historic test year.

Q. HOW WOULD THIS ADJUSTMENT CHANGE FOR A FORECASTED TEST YEAR?

A. Correcting for changes in use per customer on a forecasted test year basis is relatively straightforward. By definition, a forecasted test year is based upon estimated revenues and costs for some future period. Revenues and ultimately sales are typically based upon projections developed in a load forecast which should be similar, if not the same, as the one included in the Company's Integrated Resource Plan ("IRP"). Over the past several years, for instance, Questar's IRP has reflected longer-term trends in changes in use per customer upon which their planning process is based.

Q. COULD USAGE-RELATED CHANGES RESULTING FROM DSM ALSO BE INCLUDED IN THE FORECASTED TEST YEAR?

A. Yes, provided (1) there is no separate lost revenue recovery mechanism and the forecast is the only place where DSM-created usage changes are accounted for or (2) that any periodic lost revenue process is treated as a true up to what is included in the test year billing determinants. A DSM adjustment would be relatively straightforward calculation. First, total usage would be forecasted for several years including the test year being used to set rates. As noted earlier, this forecast, if conducted appropriately, would account for changes

in use per customer. Second, forecasted usage levels would be reduced for the anticipated savings associated with DSM programs for the years those savings are anticipated to be available.

Q. WHAT ARE SOME OF THE BENEFITS OF USING A FORECASTED TEST YEAR TO MAKE THESE TYPES OF CORRECTIONS?

A. There are at least three potential benefits. First, the use of a forecasted test year to make usage-related adjustments to rates would be based upon forward looking information that would better track anticipated trends in the near term. Second, a forecasted test year could, and probably should, be based upon the same forecasted usage information that the Company is using for its own system planning purposes. Third, and most importantly, the current risk associated with changes in sales would remain with the Company and its shareholders, and not shifted to ratepayers. Using a forecasted test year to adjust for changes in usage, particularly changes in use per customer, would be a far preferable alternative than continued use of the CET.

IX. CONCLUSIONS AND RECOMMENDATIONS

Q. WHAT ARE YOUR SPECIFIC RECOMMENDATIONS IN THIS PROCEEDING?

A. I have three primary recommendations:

- (1) The Commission should discontinue the use of the CET since it shifts considerable sales risk to ratepayers with little to no offsetting benefits for ratepayers assuming those risks. Further, the CET is overly broad in addressing the problems associated with declining

1224 use per customer trends and is unnecessary to address incentive
1225 issues associated with the promotion of DSM programs.

1226 (2) The Commission should adopt a lost revenue adjustment (“LRA”)
1227 mechanism to make the Company whole for changes in usage
1228 resulting from its DSM programs. Lost revenue recovery should be
1229 tied directly to the estimates included in the Company’s DSM cost-
1230 effectiveness filings, and updated according to the ongoing
1231 monitoring and verification (M&V) process.

1232 (3) The Commission should direct the Company to address any
1233 financial challenges created by decreases in use per customer in its
1234 next rate case through the use of a forecasted test year or some
1235 known and measurable adjustment if a historic test year is utilized
1236 for ratemaking purposes.

1237 **Q. DO YOU HAVE ALTERNATIVE RECOMMENDATIONS?**

1238 A. Yes, should the Commission reject my primary recommendations and
1239 decide to maintain the CET I would recommend:

1240 (1) The Commission require the CET to be modified such that
1241 decoupling true-ups are based upon the difference in historic and
1242 actual use per customer times test year customers (or base year
1243 customers upon which the revenue per customer statistic is
1244 derived) rather than actual customers.

1245 (2) The Commission should explicitly recognize the risk shifting nature
1246 of the CET and indicate in its Order that this shifting of risk will be
1247 considered in setting the Company's ROE in its next rate case.

1248 **Q. DOES THIS CONCLUDE YOUR TESTIMONY FILED ON JUNE 1, 2007?**

1249 **A Yes.**

**DIRECT TESTIMONY
OF
DAVID E. DISMUKES, PH.D.**

**ON BEHALF OF THE
UTAH COMMITTEE OF CONSUMER SERVICES**

ATTACHMENTS

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Master's Thesis: *Nuclear Power Project Disallowances: A Discrete Choice Model of Regulatory Decisions*

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ACADEMIC APPOINTMENTS

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2007-Current	Director, Division of Policy Analysis
2006-Current	Professor
2003-Current	Associate Executive Director
2001-2006	Associate Professor
2000-2001	Research Fellow and Adjunct Assistant Professor
1999-2000	Managing Director, Distributed Energy Resources Initiative
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2006-Current	Adjunct Professor
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Acadian Consulting Group, Baton Rouge, Louisiana

2001-Current	Consulting Economist/Principal
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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

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1993	Planning & Research Economist
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Project for an Energy Efficient Florida &
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1994	Energy Economist

Ben Johnson Associates, Inc., Tallahassee, Florida

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GOVERNMENT APPOINTMENTS

2007-Current	Louisiana Representative, Interstate Oil and Gas Compact Commission; Energy Resources, Research & Technology Committee.
2007-Current	Louisiana Representative, University Advisory Board Representative; Energy Council (Center for Energy, Environmental and Legislative Research).
2005	Member, Task Force on Energy Sector Workforce and Economic Development (HCR 322).
2003-2005	Member, Energy and Basic Industries Task Force, Louisiana Economic Development Council
2001-2003	Member, Louisiana Comprehensive Energy Policy Commission.

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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.
4. "Regulating Mercury Emissions from Electric Utilities: Good Environmental Stewardship or Bad Public Policy?" (2005). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 54 (2): 401-424
5. "Using Industrial-Only Retail Choice as a Means of Moving Competition Forward in the Electric Power Industry." (2005). With K.E. Hughes II. *Oil, Gas and Energy Quarterly*. 54(1): 211-223
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16. "Economic Displacement Opportunities in Southeastern Power Markets." (2003). With Dmitry V. Mesyanzhinov. *USAEE Dialogue*. 11: 20-24.
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36. "Stranded Investment and Non-Utility Generation." (1999). With Michael T. Maloney. *Electricity Journal* 12: 50-61.
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1. *Economic Impact Analysis of the Proposed Lake Charles Gasification Project*. (2007). Report Prepared on Behalf of Leucadia Corporation.
2. *The Economic Impacts of New Jersey's Proposed Renewable Portfolio Standard*. (2005) Report Prepared on Behalf of the New Jersey Division of Ratepayer Advocate.
3. *The Importance of Energy Production and Infrastructure in Plaquemines Parish*. (2006). Report Prepared on Behalf of Project Rebuild Plaquemines.
4. *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.
5. *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.
6. *Economic Opportunities for a Limited Industrial Retail Choice Plan in Louisiana*. (2004). With Elizabeth A. Downer and Dmitry V. Mesyanzhinov. Baton Rouge, LA: Louisiana State University Center for Energy Studies.
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8. *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.

9. *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.
10. *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.
11. *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.
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13. *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.
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15. *The Economic Impacts of Merchant Power Plant Development in Mississippi*. (2001). Report Prepared on Behalf of the US Oil and Gas Association, Alabama and Mississippi Division. Houston, TX: Econ One Research, Inc.
16. *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.
17. *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.
18. *Restructuring the Electric Utility Industry: Implications for Louisiana*. (1996). With Allan Pulsipher and Kimberly H. Dismukes. Baton Rouge, LA: Louisiana State University, Center for Energy Studies.

GRANT RESEARCH

1. *Principal Investigator*. Understanding Current and Projected Gulf OCS Labor Needs. (2007). With Allan. G. Pulsipher, Kristi A. R. Darby. U.S. Department of the Interior, Minerals Management Service. Total Project: \$346,752. (one year). Status: LOI accepted, full proposal requested and under evaluation.

2. *Principal Investigator*. Structural Shifts and Concentration of Regional Economic Activity Supporting GOM Offshore Oil and Gas Activities. (2007). With Allan. G. Pulsipher, Michelle Barnett. U.S. Department of the Interior, Minerals Management Service. Total Project: \$156,338 (one year). Status: LOI accepted, full proposal requested and under evaluation.
3. *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.
4. *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: \$134,062 (one year). Status: Awarded, In Progress.
5. *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.
6. *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.
7. *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.
8. *Principal Investigator*. "An Examination on the Development of Liquefied Natural Gas Facilities on the Gulf of Mexico." (2004). With Dmitry V. Mesyanzhinov and Mark J. Kaiser. U.S. Department of the Interior, Minerals Management Service. Total Project Funding \$101,054. Status: Awarded, In Progress.
9. *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.
10. *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.
11. *Principal Investigator*. "Marginal Oil and Gas Properties on State Leases in Louisiana: An Empirical Examination and Policy Mechanisms for Stimulating Additional Production." (2002). With Robert H. Baumann and Dmitry V. Mesyanzhinov. Louisiana Office of Mineral Resources. Total Project Funding: \$72,000. Status: Completed.
12. *Principal Investigator*. "A Collaborative Investigation of Baseline and Scenario Information for Environmental Impact Statements." (2002). With Dmitry V. Mesyanzhinov and Williams O. Olatubi. U.S. Department of Interior, Minerals Management Service. Total Project Funding:

\$600,000. Status: Awarded, In Progress, four year project.

13. *Co-Principal Investigator*. "An Analysis of the Economic Impacts of Drilling and Production Activities on State Leases." (2002) With Robert H. Baumann, Allan G. Pulsipher, and Dmitry V. Mesyanzhinov. Louisiana Office of Mineral Resources. Total Project Funding: \$8,000. Status: Completed.
14. *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.
15. *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.
16. *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.
17. *Principal Investigator*. "The Industrial Supply of Electricity: Commercial Generation, Self-Generation, and Industry Restructuring" (1996). With Andrew Kleit. Louisiana Energy Enhancement Program, LSU Office of Research and Development. Total Project Funding: \$19,948. Status: Completed.
18. *Co-Principal Investigator*. "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. U.S. Department of Interior, Minerals Management Service, Grant Number 95-0056. Total Project Funding: \$109,361. Status: Completed.

ACADEMIC CONFERENCE PAPERS/PRESENTATIONS

1. "Determining the Economic Value of Coastal Preservation and Restoration on Critical Energy Infrastructure." (2007). With Kristi A. R. Darby and Michelle Barnett. International Association for Energy Economics, Wellington, New Zealand, February 19, 2007.
2. "Regulatory Issues in Rate Design, Incentives, and Energy Efficiency." (2007). 34th Annual Public Utilities Research Center Conference, University of Florida. Gainesville, FL. February 16, 2007.
3. "An Examination of LNG Development on the Gulf of Mexico." (2007). With Kristi A.R. Darby. US Department of the Interior, Minerals Management Service. 24th Annual Information Technology Meeting. New Orleans, LA. January 9.
4. "OCS-Related Infrastructure on the GOM: Update and Summary of Impacts." (2007). US Department of the Interior, Minerals Management Service. 24th Annual Information Technology Meeting. New Orleans, LA. January 10.

5. "The Economic Value of Coastal Preservation and Restoration on Critical Energy Infrastructure." (2006). With Michelle Barnett. Third National Conference on Coastal and Estuarine Habitat Restoration. Restore America's Estuaries. New Orleans, Louisiana, December 11.
6. "The Impact of Implementing a 20 Percent Renewable Portfolio Standard in New Jersey." (2006). With Seth E. Cureington. Mid-Continent Regional Science Association 37th Annual Conference, Purdue University, Lafayette, Indiana, June 9.
7. "The Impacts of Hurricane Katrina and Rita on Energy infrastructure Along the Gulf Coast." (2006). Environment Canada: 2006 Arctic and Marine Oilspill Program. Vancouver, British Columbia, Canada.
8. "Hurricanes, Energy Markets, and Energy Infrastructure in the Gulf of Mexico: Experiences and Lessons Learned." (2006). With Kristi A.R. Darby and Seth E. Cureington. 29th Annual IAEE International Conference, Potsdam, Germany, June 9.
9. "An Examination of the Opportunities for Drilling Incentives on State Leases in Louisiana." (2005). With Kristi A.R. Darby. 28th Annual IAEE International Conference, Taipei, Taiwan (June).
10. "Fiscal Mechanisms for Stimulating Oil and Gas Production on Marginal Leases." (2004). With Jeffrey M. Burke. International Association of Energy Economics Annual Conference, Washington, D.C. (July).
11. "GIS and Applied Economic Analysis: The Case of Alaska Residential Natural Gas Demand." (2003). 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.
12. "Are There Any In-State Uses for Alaska Natural Gas?" (2002). With Dmitry V. Mesyanzhinov and William E. Nebesky. IAEE/USAEE 22nd Annual North American Conference: "Energy Markets in Turmoil: Making Sense of It All." Vancouver, British Columbia, Canada. October 7.
13. "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.
14. "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.
15. "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.
16. "Distributed Energy Resources, Energy Efficiency, and Electric Power Industry Restructuring." (1999). American Society of Environmental Science Fourth Annual Conference. Baton Rouge, Louisiana. December.

17. "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.
18. "Applied Approaches to Modeling Regional Power Markets." (1999.) With Robert F. Cope. Southern Economic Association Sixty-ninth Annual Conference. New Orleans, November 1999.
19. "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.
20. "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.
21. "Modeling Regional Power Markets and Market Power." (1999). With Robert F. Cope. Western Economic Association Annual Conference. San Diego, California. July.
22. "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.
23. "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.
24. "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.
25. "Benchmarking Electric Utility Distribution Performance." (1998) With Robert F. Cope and Dmitry Mesyanzhinov. Western Economic Association, Seventy-sixth Annual Conference. Lake Tahoe, Nevada. June.
26. "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.
27. "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.
28. "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.

29. "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
30. "Cogeneration and Electric Power Industry Restructuring." (1997). With Andrew N. Kleit. Western Economic Association, Seventy-fifth Annual Conference. Seattle, Washington. July 9-13.
31. "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.
32. "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.
33. "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.
34. "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.
35. "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.
36. "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.
37. "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.
38. "Empirical Determinants of Nuclear Power Plant Disallowances." (1995). Southern Economic Association, Sixty-Fifth Annual Conference. New Orleans, Louisiana.
39. "A Cross-Sectional Model of IntraLATA MTS Demand." (1995). Southern Economic Association, Sixty-Fifth Annual Conference. New Orleans, Louisiana.

ACADEMIC SEMINARS AND PRESENTATIONS

1. "CES Research Projects and Status." Presentation before the U.S. Department of the Interior, Minerals Management Service, Outer Continental Shelf Scientific Committee Meeting, New

Orleans, LA May 22, 2007.

2. "Hurricane Impacts on Energy Production and Infrastructure." Presentation Before the 53rd Mineral Law Institute, Louisiana State University. April 7, 2006.
3. "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.
4. "Electric Restructuring and Conservation." (2001). Presentation before the Department of Electrical Engineering, McNeese State University. Lake Charles, Louisiana. May 2, 2001.
5. "Electric Restructuring and the Environment." (1998). Environment 98: Science, Law, and Public Policy. Tulane University. Tulane Environmental Law Clinic. March 7, New Orleans, Louisiana.
6. "Electric Restructuring and Nuclear Power." (1997). Louisiana State University. Department of Nuclear Science. November 7, Baton Rouge, Louisiana.
7. "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. "Regulatory and Policy Issues in Nuclear Power Plant Development." (2007). LSU Center for Energy Studies Industry Advisory Council Meeting. Baton Rouge, LA. March 23, 2007.
2. "Oil and Gas in the Gulf of Mexico: A North American Perspective." (2007). Canadian Consulate, Heads of Mission EnerNet Workshop, Houston, Texas. March 20, 2007.
3. "Regulatory Issues for Consumer Advocates in Rate Design, Incentives & Energy Efficiency. (2007). National Association of State Utility Consumer Advocates ("NASUCA") Gas Committee Monthly Meeting. February 13, 2006.
4. "Recent Trends in Natural Gas Markets." (2006). National Association of Regulatory Utility Commissioners, 118th Annual Convention. Miami, FL November 14, 2006.
5. "Energy Markets: Recent Trends, Issues & Outlook." (2006). Association of Energy Service Companies (AESC) Meeting. Petroleum Club, Lafayette, LA, November 8, 2006.
6. "Energy Outlook" (2006). National Business Economics Issues Council. Quarterly Meeting, Nashville, TN, November 1-2, 2006.
7. "Global and U.S. Energy Outlook." (2006). Energy Virginia Conference. Virginia Military Institute, Lexington, VA October 17, 2006.
8. "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.

9. "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.
10. "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.
11. "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.
12. "Energy Sector Outlook." (2006). Baton Rouge Country Club Meeting. Baton Rouge, Louisiana. July 11, 2006.
13. "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.
14. "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.
15. "LNG—A Premier." (2006). Presentation Given to the U.S. Department of Energy's "LNG Forums." Los Angeles, California. June 1, 2006.
16. "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.
17. "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.
18. "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.
19. "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.
20. "LNG—A Premier." Presentation Given to the U.S. Department of Energy's "LNG Forums." Astoria, Washington. April 28, 2006.

21. Natural Gas Market Outlook. Invited Presentation Given to the Georgia Public Service Commission and Staff. Georgia Institute of Technology, Atlanta, Georgia. March 10, 2006.
22. 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.
23. 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
24. 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.
25. "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
26. "Hurricanes and the Outlook for Energy Markets." Presentation before the Baton Rouge Rotary Club. November 9, 2005, Baton Rouge, LA.
27. "Hurricanes, Energy Supplies and Prices." Presentation before the Louisiana Department of Natural Resources and Atchafalaya Basin Committee Meeting. November 8, 2005. Baton Rouge, LA.
28. "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.
29. "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.
30. "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.
31. "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.
32. "Louisiana Power Industry Overview." Presentation before the Clean Air Interstate Rule Implementation Stakeholders Meeting. August 11, 2005. Louisiana Department of Environmental Quality.
33. "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.

34. "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.
35. "The Outlook for Energy." Lagniappe Studies Continuing Education Course. Baton Rouge, LA. July 11, 2005.
36. "The Outlook for Energy." Sunshine Rotary Club. Baton Rouge, LA. April 27, 2005.
37. "Background and Overview of LNG Development." Energy Council Workshop on LNG/CNG. Biloxi, Ms: Beau Rivage Resort and Hotel, April 9, 2005.
38. "Natural Gas Supply, Prices, and LNG: Implications for Louisiana Industry." Cytec Corporation Community Advisory Panel. Fortier, LA January 14, 2005.
39. "The Economic Opportunities for a Limited Industrial Retail Choice Plan." Louisiana Department of Economic Development. Baton Rouge, Louisiana. November 19, 2004.
40. "Energy Issues for Industrial Customers of Gas and Power." Louisiana Association of Business and Industry, Energy Council Meeting. Baton Rouge, Louisiana. October 11, 2004.
41. "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.
42. "Energy Issues for Industrial Customers of Gas and Power." American Institute of Chemical Engineers – New Orleans Section. New Orleans, LA. September 22, 2004.
43. "Natural Gas Supply, Prices and LNG: Implications for Louisiana Industry." Dow Chemical Company Community Advisory Panel Meeting. Plaquemine, LA. August 9, 2004.
44. "Energy Issues for Industrial Customers of Gas and Power." Louisiana Chemical Association Post-Legislative Meeting. Springfield, LA. August 9, 2004.
45. "LNG In Louisiana." Joint Meeting of the Louisiana Economic Development Council and the Governors Cabinet Advisory Council. Baton Rouge, LA. August 5, 2004.
46. "Louisiana Energy Issues." Louisiana Mid-Continent Oil and Gas Association Post Legislative Meetings. Sandestin, Florida. July 28, 2004.
47. "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.
48. "Natural Gas and LNG Issues for Louisiana." Presentation before the Rhodia Community Advisory Panel. May 20, 2004, Baton Rouge, LA.

49. "The Economic Opportunities for LNG Development in Louisiana." Presentation before the Louisiana Chemical Association Plant Managers Meeting. May 27, 2004. Baton Rouge, LA.
50. "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.
51. "The Economic Opportunities for LNG Development in Louisiana." Presentation before the Petrochemical Industry Cluster, Greater New Orleans, Inc. May 19, 2004, Destrehan, LA.
52. "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.
53. "The Economic Opportunities for LNG Development in Louisiana." Presentation before the Board of Directors, Greater New Orleans, Inc. May 13, 2004, New Orleans, LA.
54. "Natural Gas Outlook: Trends and Issues for Louisiana." Presentation before the Louisiana Joint Agricultural Association Meetings. January 14, 2004, Hotel Acadiana, Lafayette, Louisiana.
55. "Natural Gas Outlook" Presentation before the St. James Parish Community Advisory Panel Meeting. January 7, 2004, IMC Production Facility, Convent, Louisiana.
56. "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.
57. "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.
58. "Affordable Energy: The Key Component to a Strong Economy." Presentation before the National Association of Regulatory Utility Commissioners ("NARUC"), November 18, 2003, Atlanta, Georgia.
59. "Natural Gas Outlook." Presentation before the Louisiana Chemical Association, October 17, 2003, Pointe Clear, Alabama.
60. "Issues and Opportunities with Distributed Energy Resources." Presentation before the Louisiana Biomass Council. April 17, 2003, Baton Rouge, Louisiana.
61. "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.
62. "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.

63. "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.
64. "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.
65. "Merchant Power and Deregulation: Issues and Impacts." Presentation before the Air and Waste Management Association Annual Meeting. Baton Rouge, LA, November 15, 2001.
66. "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.
67. "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.
68. "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.
69. "The Changing Nature of the Electric Power Business in Louisiana." Presentation before the Louisiana Department of Environmental Quality. Baton Rouge, LA, August 27, 2001.
70. "Power Business in Louisiana: Background and Issues." Presentation before the Louisiana Interagency Group on Merchant Power Development. Baton Rouge, LA, July 16, 2001.
71. "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.
72. "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.
73. "The Economic Impacts of Merchant Power Plant Development In Mississippi." Presentation before the Mississippi Public Service Commission. Jackson, Mississippi, March 20, 2001.
74. "Energy Conservation and Electric Restructuring." With Ritchie D. Priddy. Presentation before the Louisiana Department of Natural Resources. Baton Rouge, Louisiana, October 23, 2000.
75. "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.

76. "Electric Reliability and Merchant Power Development Issues." Technical Meetings of the Louisiana Public Service Commission. Baton Rouge, LA. August 29, 2000.
77. "A Introduction to Distributed Energy Resources." Summer Meetings, Southeastern Association of Regulatory Utility Commissioners (SEARUC). New Orleans, LA. June 27, 2000.
78. Roundtable Moderator/Discussant. Mid-South Electric Reliability Summit. U.S. Department of Energy. New Orleans, Louisiana. April 24, 2000.
79. "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.
80. "LSU/CES Distributed Energy Resources Initiatives." Los Alamos National Laboratories. Office of Energy and Sustainable Systems. Los Alamos, New Mexico. February 16, 2000.
81. "Distributed Energy Resources Initiatives." Louisiana State University, Center for Energy Studies Industry Associates Meeting. Baton Rouge, Louisiana. December 15, 1999.
82. "Merchant Power Opportunities in Louisiana." Louisiana Mid-Continent Oil and Gas Association (LMOGA) Power Generation Committee Meetings. Baton Rouge, Louisiana. November 10, 1999.
83. 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.
84. "The Political Economy of Electric Restructuring In the South" Southeastern Electric Exchange, Rate Section Annual Conference. New Orleans, Louisiana. May 7, 1999.
85. "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.
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. Lafayette, Louisiana, March 24, 1999.
87. "What's Happened to Electricity Restructuring in Louisiana?" Louisiana State University, Center for Energy Studies Industry Associates Meeting. March 22, 1999.
88. "A Short Course on Electric Restructuring." Central Louisiana Electric Company. Sales and Marketing Division. Mandeville, Louisiana, October 22, 1998.
89. "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.

90. "How Will Utility Deregulation Affect Tourism." Louisiana Travel Promotion Association Annual Meeting, Alexandria, Louisiana. January 15, 1998.
91. "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.
92. "Electric Utility Restructuring in Louisiana." Hammond Chamber of Commerce, Hammond, Louisiana. October 30, 1997.
93. "Electric Utility Restructuring." Louisiana Association of Energy Engineers. Baton Rouge, Louisiana. September 11, 1997.
94. "Electric Utility Restructuring: Issues and Trends for Louisiana." Opelousas Chamber of Commerce, Opelousas, Louisiana. June 24, 1997.
95. "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.
96. "Electric Restructuring: Louisiana Issues and Outlook for 1997." Louisiana State University, Center for Energy Studies Industry Associates Meeting, Baton Rouge, Louisiana, January 15, 1997.
97. "Restructuring the Electric Utility Industry." Louisiana Propane Gas Association Annual Meeting, Alexandria, Louisiana, December 12, 1996.
98. "Deregulating the Electric Utility Industry." Eighth Annual Economic Development Summit, Baton Rouge, Louisiana, November 21, 1996.
99. "Electric Utility Restructuring in Louisiana." Jennings Rotary Club, Jennings, Louisiana, November 19, 1996.
100. "Electric Utility Restructuring in Louisiana." Entergy Services, Transmission and Distribution Division, Energy Centre, New Orleans, Louisiana, September 12, 1996
101. "Electric Utility Restructuring" Louisiana Electric Cooperative Association, Baton Rouge, Louisiana, August 27, 1996.
102. "Electric Utility Restructuring -- Background and Overview." Louisiana Public Service Commission, Baton Rouge, Louisiana, August 14, 1996.
103. "Electric Utility Restructuring." Sunshine Rotary Club Meetings, Baton Rouge, Louisiana, August 8, 1996.
104. 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.

105. 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, RECOMMENDATIONS, AND AFFIDAVITS

1. Expert Report, Recommendation, and Proposed Rule: Docket Number R-29712, ex parte. (2007.) Before the Louisiana Public Service Commission. In re: Investigation into the ratemaking and generation planning implications of nuclear construction in Louisiana. On the behalf of the Louisiana Public Service Commission Staff. Report and Recommendation. Issues: nuclear cost power plant development, generation planning issues, and cost recovery issues.
2. Expert Testimony: Case Number U-14893 (2006). 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. On the behalf of the Michigan Attorney General. Issues: Rate Design, revenue decoupling, financial analysis, demand-side management program and energy efficiency policy. (Direct and Rebuttal Testimony).
3. Expert Report, Recommendation, and Proposed Rule: Docket Number R-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; ratepaying impacts of new environmental regulations.
4. 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.
5. 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.
6. Expert Testimony: 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)
7. 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.
8. Expert Report: 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.
9. Expert Testimony: 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).
 10. Expert Testimony: 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.
 11. Expert Testimony: 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.
 12. Comments on Decreased Drilling Activities in Louisiana and the Role of Incentives. (2005). Louisiana Mineral Board Monthly Docket and Lease Sale. July 13, 2005
 13. 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.
 14. Docket No. U-21453. (2005). Technical Conference before the Louisiana Public Service Commission. Comments on an Investigation for a Limited Industrial Retail Choice Plan.
 15. Expert Testimony: 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.
 16. Expert Report and Testimony: 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.
 17. Expert Testimony: 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.
 18. Expert Report and Recommendation: 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.

19. Expert Testimony: 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)
20. Expert Testimony: 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.
21. Expert Affidavit: 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.
22. 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.
23. Expert Report and Testimony: 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.
24. Expert Testimony: 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.
25. Public Testimony: Louisiana Board of Commerce and Industry (2001). Testimony on the Economic Impacts of Merchant Power Generation.
26. Expert Testimony: 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.
27. 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).
28. Expert Testimony: 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.

29. Expert Affidavit: 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.
30. 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.
31. Public Testimony: 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.
32. Expert Testimony: 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.
33. Expert Testimony: 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.
34. Expert Testimony: 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.
35. Expert Testimony: 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.
36. Expert Testimony: 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.
37. Louisiana House of Representatives, Special Subcommittee on Utility Deregulation. (1997). On Behalf of the Louisiana Public Service Commission Staff. Issue: Electric Restructuring.
38. Expert Testimony: 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.

39. Expert Testimony: 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.
40. Expert Testimony: 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* (2004).

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).

1 Senior Honors Thesis (Journalism, Loyola University)

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

Program Committee Chairman (2007). USAEE Annual Conference, New Orleans, LA

Finance Committee Chairman (2007). USAEE Annual Conference, New Orleans, LA

Committee Member (2006), IAEE Nominating Committee.

Founding President (2005-2007) 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).

Attachment 2 – Overview of States Where Decoupling was Rejected or Withdrawn

Arizona

On December 9, 2004, Southwest Gas Corporation filed with the Arizona Corporation Commission ("ACC") an application for a rate increase. Included in the application was a proposal for a decoupling mechanism called a Conservation Margin Tracker ("CMT"). The CMT would address the Company's ongoing inability to achieve its authorized rate of return due, at least in part, to declining per customer usage on its system. Southwest Gas proposed that the CMT be imposed only on the residential class (although it did not oppose broader application). Under the CMT, if Southwest Gas did not achieve its authorized "margin" (i.e., all costs of providing gas less the cost of the gas itself) per customer class, the CMT would track that shortfall and impose a surcharge on customers in that class the following year based on the prior year's revenue shortfall. In effect, the CMT would insulate Southwest Gas from the risk associated with declining gas usage by customers.

Southwest Gas claimed that the CMT is a reasonable cost recovery mechanism as it would eliminate the financial disincentive associated with promoting DSM; it would not discourage consumers from conserving natural gas because the more a customer conserves the more the customer would save; it would charge customers only the fixed costs of service that the Commission authorized in the rate case; it would protect customers from the Company earning more than its authorized margin per customer during a colder than normal heating season; it would protect the Company from declining residential use per customer; and it would provide the Company with a more consistent revenue stream by reducing its dependency on gas sales to recover the authorized margin per customer, thus having a positive impact on the Company's ratings with credit agencies and reducing borrowing costs needed to fund infrastructure growth.

The Arizona Commission Staff opposed adoption of the CMT arguing that if natural gas is relatively inelastic, as the Company contends, the potential for ongoing conservation would be mitigated and usage levels will stabilize over time, thus minimizing the declining usage that impacts the Company's revenues. The Residential Utility Consumer Office also opposed the CMT proposal as did SWEEP/NRDC. SWEEP/NRDC expressed understanding of the dilemma faced by Southwest Gas with respect to decreasing usage and revenues. However, its witness stated that a full analysis of the benefits and drawbacks of decoupling mechanisms for LDCs warrant consideration in a broader context.

The ACC recognized that Southwest Gas is facing increased financial pressure due to declining per customer usage. It stated:

"There is conflicting evidence in the record as to whether the recent level of declining per customer usage will continue into the foreseeable future, and whether conservation efforts are the direct cause of Southwest Gas' inability to earn its authorized return from such customers."

The Commission added:

“The Company is requesting that customers provide a guaranteed method of recovering authorized revenues, thereby virtually eliminating the Company's attendant risk. Neither the law nor sound public policy requires such a result and we decline to adopt the Company's CMT in this case.”

[Docket No. G-01551A-04-0876, Decision No. 68487, Arizona Corporation Commission, February 23, 2006]

Arkansas

On November 24, 2004, CenterPoint Energy Arkla ("Arkla") filed an Application for approval of a general change or modification in its rates and tariffs. Included in the filing were three proposed riders: (1) a Load Change Adjustment, which would provide margin recovery due to the decline in customers and the decline in average use per customer; (2) an Infrastructure Cost Recovery Rider, which provides for the recovery of the cost of capital related to certain non-revenue producing capital investments in natural gas facilities and certain operating expenses; and (3) if the Commission chooses not to adopt the LCA and/or ICR, a Rate Stabilization Plan ("RSP") which would adjust Arkla's rates or credit customer bills annually to reflect changes in costs and revenues.

Arkla proposed that the customer charge for the RS-1 class increase from \$9.75 to \$17.00. The Company also proposed to decrease the amount of usage applicable to the first block from 50 CCF to 15 CCF, increase that block's charge from \$0.2630 to \$0.8267, and decrease the second block from \$0.1847 to \$0.0572. The Commission agreed with both Staff and the Attorney General that Arkla's proposed rate design for the RS-1 class would have severe rate shock impacts on many residential customers, especially lower income customers. The Commission found that the Residential Class should pay its cost of service, that the RS-1 customer charge rate should remain at the current level, and that the residential rate decrease from Staff's cost of service should be accomplished by reducing the rates applicable to the second block.

Regarding the RSP, the Attorney General argued that it is one-sided and it protects Arkla from all risk on the downside, but only results in a small sharing of the upside risk. He also pointed out that the RSP is one-sided in that it provides permanent rate increases when earnings shortfalls occur. However, when earnings surpluses arise, one time bill credits or refunds are given for a portion of the excess. He noted that while performance based regulation mechanisms have been given greater consideration in recent years, Arkla's proposed RSP does not qualify as performance based regulation. The Arkansas PSC agreed with the Attorney General that the RSP is one-sided in favor of the Company and investors.

"When earnings are below the proposed deadband, or more than 50 percent basis points below the allowed ROE midpoint, revenues would be increased by an amount necessary to bring the earned ROE back to the midpoint or allowed ROE. In contrast, when rates are above the upper end of the deadband, or more than 50 basis points above the allowed ROE, the Company would refund only a portion of the excess over the upper end of the deadband. Moreover, because rates themselves are not changed, Arkla would be left with the potential to over-earn again the following year. Accordingly, we reject the RSP."

[Docket No. 04-121-U, Order No. 16, Arkansas Public Service Commission, September 19, 2005]

Connecticut

During its June 2005 Special Session, the General Assembly passed Public Act No. 05-01, An Act Concerning Energy Independence. In Section 21 of the Act, the Department of Public Utility Control ("DPUC") was directed to investigate the decoupling of sales from earnings for energy distribution companies ("DCs") to promote the state's energy policy and provide a report to the General Assembly. The DPUC looked at decoupling and its potential as a tool for promotion of the state's energy policy when applied to gas and electric utilities. The DPUC found:

"that decoupling by itself does not provide an incentive to energy DCs to promote conservation. Rather, in helping to ensure fixed cost recovery, it removes a disincentive for companies to promote conservation. However, it may also shift to ratepayers such normal business risks as lower sales due to economic downturns, weather, new energy efficiency technology, and demand response to price increases. This report discusses mechanisms for various degrees of decoupling ranging from partial to full decoupling. In general, the more complete the decoupling, the more business risks are shifted from the energy DCs to the ratepayers."

The DPUC also found that the states utilities are "performing well. Incentives available to the electric DCs and their customers promote conservation and load management."

In Connecticut, two of the three natural gas LDCs do have conservation adjustment mechanisms ("CAM") in connection with their energy efficiency programs for low-income customers. The CAM is listed as a charge or credit on customers' monthly bills. Any amount spent on conservation over or under the approved base rate amount is reconciled through the monthly CAM. There is also a lost sales revenue adjustment included in the CAM. It provides payment for lost sales due to conservation achieved by gas LDC-sponsored conservation programs.

[Docket No. 05-09-09, Connecticut Department of Public Utility Control, January 18, 2006]

Delaware

On August 31, 2006, Delmarva Power & Light Company filed an application with the Delaware Public Service Commission seeking approval for an overall increase in natural gas base (delivery) rates of \$14,967,000, or approximately 6.62 percent over currently approved rates. The Application also included proposed modifications to the Company's gas tariff relating to "Reconnect" and "Premise Collection" fees and a new Bill Stabilization Adjustment ("BSA") mechanism. The BSA, if approved, would allow the Company to adjust its base (delivery) rates to reflect actual changes to the revenue it collects on a per customer basis, thereby "decoupling" revenues from sales.

On February 20, 2007, the parties submitted a "Proposed Settlement Agreement" dated February 15, 2007, which, if approved, would resolve (or defer) all contested issues in the case. The Proposed Settlement calls for an annual revenue increase of \$9.0 million, or approximately 3.9 percent of total gas revenues, and reflects a cost of equity of 10.25 percent. It also defers consideration of the BSA until the Commission initiates a generic statewide proceeding regarding decoupling mechanisms for gas and electric distribution utilities.

In its prefiled testimony Staff recommended that the Commission decline to implement the Company's proposed BSA because it was not supported by appropriate financial evidence (such as "backcasting") and would have a disproportionate impact on customers in smaller classes who reduced their consumption. In this regard, Staff recommended that the Commission open a generic proceeding to investigate whether revenue decoupling might be appropriate and, if so, the manner in which it might be implemented. In the event that the Commission approved the Company's proposed BSA, then Staff recommended that the Company's return on equity be reduced by 50 basis points to reflect the greater revenue security that would result from the BSA.

[Docket No. 06-284, Order No. 7152, Delaware Public Service Commission, March 20, 2007]

Iowa

On February 9, 2006, the Utilities Board ("IUB") initiated an inquiry into the effect of reduced natural gas usage resulting from increased energy efficiency and other factors over the next five years on the non-gas revenues of Iowa's rate-regulated natural gas utilities. The IUB stated that the inquiry would investigate the potential effects of a multi-state natural gas price reduction initiative and other factors in reducing natural gas usage, the resulting effect on regulated non-gas utility revenues, and would consider whether traditional regulation is flexible enough to address these effects or whether alternative mechanisms or approaches, such as a decoupling mechanism to reduce the influence of sales volumes on utility earnings, might be appropriate.

Based upon the information reviewed by the IUB, the tension between energy efficiency and Iowa natural gas utilities' opportunity to earn their authorized rate of return did not appear to be a substantial problem in Iowa. Iowa utilities have been participating in energy efficiency plans since before 1990 without substantial adverse effects on earnings. In 1990, Iowa established a statutory goal in Iowa Code § 473.3 to "more efficiently utilize energy resources ... to decrease the state's dependence on energy resources from outside the state by reducing the amount of energy used." This goal was to be implemented through the development of programs that promote energy efficiency and energy conservation by all Iowans.

To meet this statutory goal, the IUB developed rules and procedures for planning and implementing energy efficiency programs by Iowa public utilities and has approved several rounds of energy efficiency plans for rate-regulated utilities, most recently in 2003. The energy and peak capacity saved by investor-owned utility energy efficiency programs over the past 15 years have resulted in a cumulative reduction in natural gas usage through 2005 of about 7 million MCF, or about 6.6 percent of annual retail natural gas sales. By 2005, total customer retail cost savings resulting from these cumulative changes in energy use amounted in 2005 to about \$ 80 million in natural gas costs.

From this, the IUB concluded that:

"Iowa utilities have not been unable to engage in meaningful energy efficiency programs because of concern about their earnings. The IUB is committed to the continuation of the aggressive energy efficiency programs already in place and to the development of new plans to further increase savings to customers and reduced natural gas consumption from increased energy efficiency. This increase in energy efficiency programs by utilities and their customers may have an adverse effect on the ability of rate-regulated utilities to have a reasonable opportunity to earn their authorized rates of return, potentially creating a disincentive to utility participation in these programs. Other jurisdictions that lack the energy efficiency mandate and history of Iowa have adopted

decoupling mechanisms. The Board believes this may be appropriate in situations where reduced natural gas usage resulting from energy efficiency programs may adversely affect earnings. When this situation exists, utilities should be able to propose appropriate mechanisms to provide the utilities with a reasonable opportunity to earn their authorized rates of return in spite of reduced sales volumes. The information reviewed in this inquiry does not demonstrate that situation for Iowa utilities to date, but the Iowa utilities in this docket have nonetheless proposed several different alternatives solutions to declining customer usage, perhaps in anticipation of increased emphasis on energy efficiency programs. The suggested changes included rate design proposals, incentive mechanisms, and automatic rate adjustments, among other things.”

The IUB also noted that one reason that Iowa utilities may not be subject to the same pressures as utilities in other jurisdictions is that the IUB allows recovery of the costs associated with approved energy efficiency plans through an automatic adjustment mechanism for natural gas utilities, the Energy Efficiency Cost Recovery (EECR). This pass through of energy efficiency plan costs alleviates some of the disincentive for utilities to promote greater energy efficiency by customers. The IUB recognizes that the EECR may not be a complete answer, however, as it compensates utilities for expenditures but does not address the possible adverse effect reduced energy consumption might have on utility returns.

[Docket No. NOI-06-1, Iowa Utilities Board, December 18, 2006]

State: Kansas

Summary: In September 2006, the Kansas Corporation Commission (“KCC”) opened a docket to investigate energy efficiency programs, and specifically the KCC’s legal authority with regard to energy efficiency programs. The KCC concluded that all jurisdictional electric and natural gas utilities should be made parties to the docket as well as the Sierra Club. The threshold question is the extent to which the KCC has legal authority to require or encourage electric and natural gas utilities to offer energy efficiency programs. Questions were offered for comment, including some focused on decoupling:

- May the Commission authorize a “decoupling” of revenue requirements from usage in order to remove disincentives for energy efficiency?
- Is “decoupling” of revenue requirements from sales volumes a necessary or desirable mechanism to remove disincentives for energy efficiency programs? What are the pros and cons of such a mechanism? If decoupling is not implemented, is it appropriate and desirable to have an *ex poste* mechanism to recover lost margins from sales not made due to energy efficiency investments? What are the pros and cons of this approach?

The KCC Staff issued a Report and Recommendation on May 8, 2007 concluding that the KCC has the authority to approve energy efficiency programs offered by the utilities. However, there was disagreement among the parties as to whether the KCC could require these programs. Staff concluded that the KCC does have the authority and that the authority extends to an ability to ‘decouple’ revenue requirements from usage. Although there was disagreement as to whether decoupling is a good policy, the KCC does have the legal authority to implement such a process.

Meanwhile, on November 1, 2006, Aquila filed an application to increase base rates by \$7.2 million. The filing also included a decoupling mechanism that would recover more of the Company’s fixed costs in an increased demand charge that would rise to \$13 per month from \$12 per month.

On April 19, 2007 a Stipulated Settlement Agreement was entered into by the Commission Staff, the Citizens’ Utility Ratepayer Board, Aquila, Inc., Cornerstone Energy, and United School District No. 259. The parties agreed to a rate increase of \$5.1 million. In addition, “Aquila has specifically agreed that its demand based rate design proposal is not adopted in this case. Instead, the rates and traditional rate design resulting from the \$5.1 million increase have been agreed to and are set forth in Schedule 1 to the Agreement. The parties have agreed that said rate design is a fair compromise in this case.” On May 16, 2007 the KCC issued an Order approving the Stimulated Settlement Agreement.

[Docket No 07-GIMX-247-GIV, Kansas Corporation Commission, September 11, 2006; and 07-AQLG-431-RTS, Kansas Corporation Commission, April 20, 2007]

State: Michigan

Summary: On May 25, 2006, SEMCO Energy Gas Company (SEMCO) filed an application, with supporting testimony and exhibits requesting authority to increase its overall cost of service revenue requirement by \$18,098,051, an increase in the rates for its sales and transportation customers, and a redesign of its residential service rates. On June 16, 2006, SEMCO submitted an amended application and amended testimony and exhibits. The amended application adjusted SEMCO's request for an increase in its overall cost of service revenue requirement to \$18,856,897.

As part of its rate redesign proposals, SEMCO Gas sought to (i) replace the residential monthly customer charge and the volumetric distribution charge with a single fixed residential monthly service charge, or alternatively, only replace the volumetric distribution charge with a fixed residential monthly service charge and retain a separate residential monthly customer charge; (ii) remove Lost and Unaccounted For ("LAUF") gas costs from base rates and collect LAUF gas costs as a booked cost of gas sold through the GCR process; (iii) alternatively, retain LAUF gas costs in base rates at an appropriate level and "true up" this amount to match the Company's actual LAUF gas costs on an annual basis; (iv) "true up" the amount of Uncollectible Expense in base rates to match the Company's actual Uncollectible Expense on an annual basis; and (v) implement surcharges to recover costs associated with: (a) a residential conservation program and participation in Michigan's Low Income Energy Efficiency Fund, and (b) an accelerated program for replacement of unprotected and bare steel mains and compressors.

In December 2006 the parties submitted a settlement agreement resolving all the issues in the case. The portion of SEMCO's revenue requirement allocated to its residential customer class will be collected through a monthly customer charge of \$10.00 and a volumetric distribution rate of \$1.5817 per Mcf based on a billing determinant of 96.0 Mcf annual per customer consumption. Also as part of the settlement, the proposed change in rate design was dropped.

[Case No. U-14893; Michigan Public Service Commission, January 9, 2007; and Case No. U-14893, SEMCO Energy Gas Company Application, May 25, 2006]

State: Nevada

Summary: In its 2004 rate case, Southwest Gas proposed a Margin Per Customer Balancing Provision ("MCB") that would decouple residential non-gas (margin) revenue recovery from the volume of gas delivered in a given month and re-couples margin revenue recovery to the number of residential customers served each month. The Company explained that a MCB protects residential customers against margin over-collections and protects Southwest against margin under-collections due to differences between adopted test year residential consumption per customer and consumption per customer experienced in future periods. This is accomplished through the establishment of a balancing account that records the difference between authorized margin per customer and actual billed margin per customer on a monthly basis. Periodically the balance in the account would be returned or recovered from ratepayers. According to Southwest Gas, a MCB "would have no effect on the economic incentives for gas customers to pursue conservation and energy efficiency because the best incentive to conserve is the savings in purchased gas costs that customers obtain when their usage decreases."

The Commission stated that establishing the MCB would be a significant change from current practice and before such change is authorized, the Commission must be able to arrive at the conclusion that the proposed change is the right thing to do to address the perceived problem. The Commission could not conclude that the evidence is compelling to establish the MCB, especially prior to using other more recognized alternatives. Therefore, the Commission did not amend Southwest's billing practice.

In its order, the Commission chose alternative methods to assist with stable earnings such as the hypothetical capital structure, the variable interest rate recovery mechanism, the increase to the basic customer charge, its encouragement to use more frequent rate filings with certifications for updating information as necessary, and the overall rate design. It also stated:

"General rate cases allow the Commission to establish new rates based on the most current financial and customer sales information. Nevada law allows a utility to mitigate regulatory lag by updating its test period costs with a certification period. If Southwest utilizes these tools, coupled with the other benefits mentioned above, the Commission expects to see an improvement in the level and stability of Southwest's earnings. Southwest can re-evaluate the statutory authority and the need for an MCB approach after the benefits of these alternatives are experienced and evaluated."

[Docket No. 04-3011, Nevada Public Service Commission, August 26, 2004]

State: New York

Summary: On April 30, 2004, the Consolidated Edison filed a cover letter, proposed new tariff leaves, 28 pieces of direct testimony, and four volumes of exhibits in support of three annual delivery service revenue increases and other changes. The annual delivery service revenue increases proposed to be recovered through rates at the time were \$550 million for the first rate year (April 1, 2005 through March 31, 2006 or rate year one), \$175.3 million for the second rate year (April 1, 2006 through March 31, 2007 or rate year two), and \$289 million for the third rate year (April 1, 2007 through March 31, 2008 or rate year three).

During the proceeding the NRDC and the Pace Law School Energy Project ("Pace") recommended that the Commission require a Revenue Decoupling Mechanism ("RDM") be developed "to ensure that Con Edison would be made whole for all delivery service revenues lost from demand management ("DM"), whether or not the DM is the result of the DM initiatives in this case."

Con Edison, DPS Staff, and the City all opposed the RDM proposal. They criticized NRDC's failure to develop a specific RDM proposal. In addition the three parties contended that the Company's proposed incentive and lost revenue provisions are reasonable and need not be changed. The DPS Staff described NRDC's and Pace's concerns as speculative and unwarranted to the extent: (1) much DM is ongoing without an RDM; and (2) the Company's failure to meet the requirements of the Commission Order on DM could result in penalties of up to \$100,000 per day. The gist of these and related arguments is that the proposals for a significant increase in DM, for an incentive, and for the Company's recovery of lost delivery service revenues are reasonable overall, and that the balance reflected among the Applicant's terms should not be disturbed because of NRDC's and Pace's RDM proposal.

Con Edison and DPS Staff argued that even if one agrees that an RDM makes some theoretical sense, it cannot be assumed that such a mechanism will be effective. They both emphasized the lack of evidence about how effective an RDM mechanism might be. It was suggested during the hearings that an effective RDM is in effect for Pacific Gas and Electric. However, DPS Staff suggests this is not nearly enough information to establish that the RDM in question is effective in fact.

The fourth general argument offered in opposition to an RDM is that it would be very hard, if not impossible, to develop an RDM that would address all the problems experienced in New York in the past (large deferrals, rate instability, and rate uncertainty) without creating any new ones. The suggestion here is that it would be exceedingly complex and administratively burdensome to develop an RDM that isolates the effects of weather, economic growth, and other non-DM factors and provides only for the recovery of revenues lost because of DM.

The Commission stated that it agreed that

“there is a conflict between the DM goal of reducing sales and the Company's economic incentive to increase sales. We also agree that the Company's sales in the three rate years, all other things being equal, might be lower than projected by a specific amount solely because of DM beyond the levels assumed for purposes of calculating the delivery service revenue requirements or that might result from DM initiatives that would be captured in the lost revenue mechanism for this case. We disagree, however, that the sole reasonable regulatory approach for eliminating this conflict is to adopt an RDM.”

[CASE 04-E-0572, New York Public Service Commission, March 24, 2005]

State: Washington

Summary: On May 5, 2005, PacifiCorp filed a general rate case with the Commission in Docket UE-050684, proposing revisions to its currently effective Tariff WN-U-74 and requesting an increase in annual revenues from Washington operations of \$39.2 million, which would result in a proposed increase in rates of 17.9 percent.

In this proceeding, PacifiCorp and NRDC jointly proposed a three-year pilot decoupling mechanism with the following features:

- Segregating the fixed cost revenue requirement from the variable cost requirement.
- True-up mechanism
- Weather risk excluded.
- Three-year pilot/independent assessment.
- Tariff filing.
- Wholesale sales impact.

Staff opposed the joint proposal because it fails to: 1) Provide detailed tariffs or accounting rules governing the operation of the true-up mechanism; 2) Quantify the effect the mechanism may have on risks associated with recovery of fixed costs, and; 3) Identify or commit to any new demand-side management benefit for ratepayers to compensate for shifting the risk of conservation to them. Staff objected to including generation and transmission fixed costs that are subject to the Company's Revised Protocol allocation methodology. Staff also asserted the Company is currently capturing all cost-effective conservation measures in its Integrated Resource Plan and receiving adequate compensation for any reduction in retail sales through revenues derived from its wholesale sales.

Public Counsel faulted the proposal for many of the same reasons identified by Staff, and further asserted the proposal: 1) Changes ratemaking from a cost-based approach to one tying revenues to the number of customers served; 2) Fails to recognize the windfall to the Company if the potential for profit from wholesale sales is not taken into account, and; 3) May not be compatible with the PCAM proposed by the Company.

The Washington Utilities and Transportation Commission ("WUTC") rejected the joint decoupling proposal. The WUTC, while being open to the idea of revenue decoupling, found several problems with PacifiCorp's proposal. Namely, that the proposal was not well-founded, documented, and did not have firm commitments for explicit DSM programs. The WUTC ruled:

"We favor utility efforts that accomplish cost-effective conservation through reducing utility costs and allowing consumers to manage their bills. A well-designed decoupling mechanism may support the Company's increased investment in energy conservation and

promote our state's goal of furthering energy conservation. We must reject the specific joint proposal offered by the Company and NRDC, however, for the following reasons: 1) We cannot calculate the mechanism's fixed cost revenue requirement without first having adopted an allocation methodology sufficient to make rates; 2) The proposal lacks important analysis of implementation costs and its impact on the Company's overall revenues and cost of equity, and; 3) The Company has failed to identify and commit to incremental conservation measures as a counterbalance to its potential reduction in risk. We expect the Company to provide such evidence to allow us to fully consider a decoupling proposal."

[Docket UE-050684, Order 04, Docket UE-050412, Order 03, Washington Utilities and Transportation Commission, April 17, 2006, Dated]

State: Wisconsin

Citation:

Summary: In August 2005, Wisconsin Power & Light filed an application for a rate increase based on an extraordinary increase in fuel costs. Another application was filed in November 2005 seeking a further increase again based on an extraordinary increase in fuel costs. As part of this proceeding, the Citizens Utility Board proposed a revenue decoupling mechanism called a 'true-up mechanism' to give back or restore the difference between authorized fixed cost recovery and actual recovery based on actual sales.

In September 2006 the Commission received a stipulation signed by the active parties in the docket. The Commission accepted the stipulation as a resolution of all issues in this matter. The Citizens Utility Board proposed 'true-up' mechanism was not part of this stipulation.

[Docket 6680-UR-114, Public Service Commission of Wisconsin, September 29, 2006]

**DIRECT TESTIMONY
OF
DAVID E. DISMUKES, PH.D.**

**ON BEHALF OF THE
UTAH COMMITTEE OF CONSUMER SERVICES**

EXHIBITS

Example of Revenue Decoupling

Utah Committee of Consumer Services
 Witness: David Dismukes
 Docket No. 05-057-T01
 CCS Exhibit 1.1

Allowed Revenue per Customer (Annual)

Current Non-Gas Revenue	\$ 150,000,000
2005 Number of Customers	600,000
Volumetric Charge per Customer	\$250.00

Allowed Revenue per Customer (Monthly)

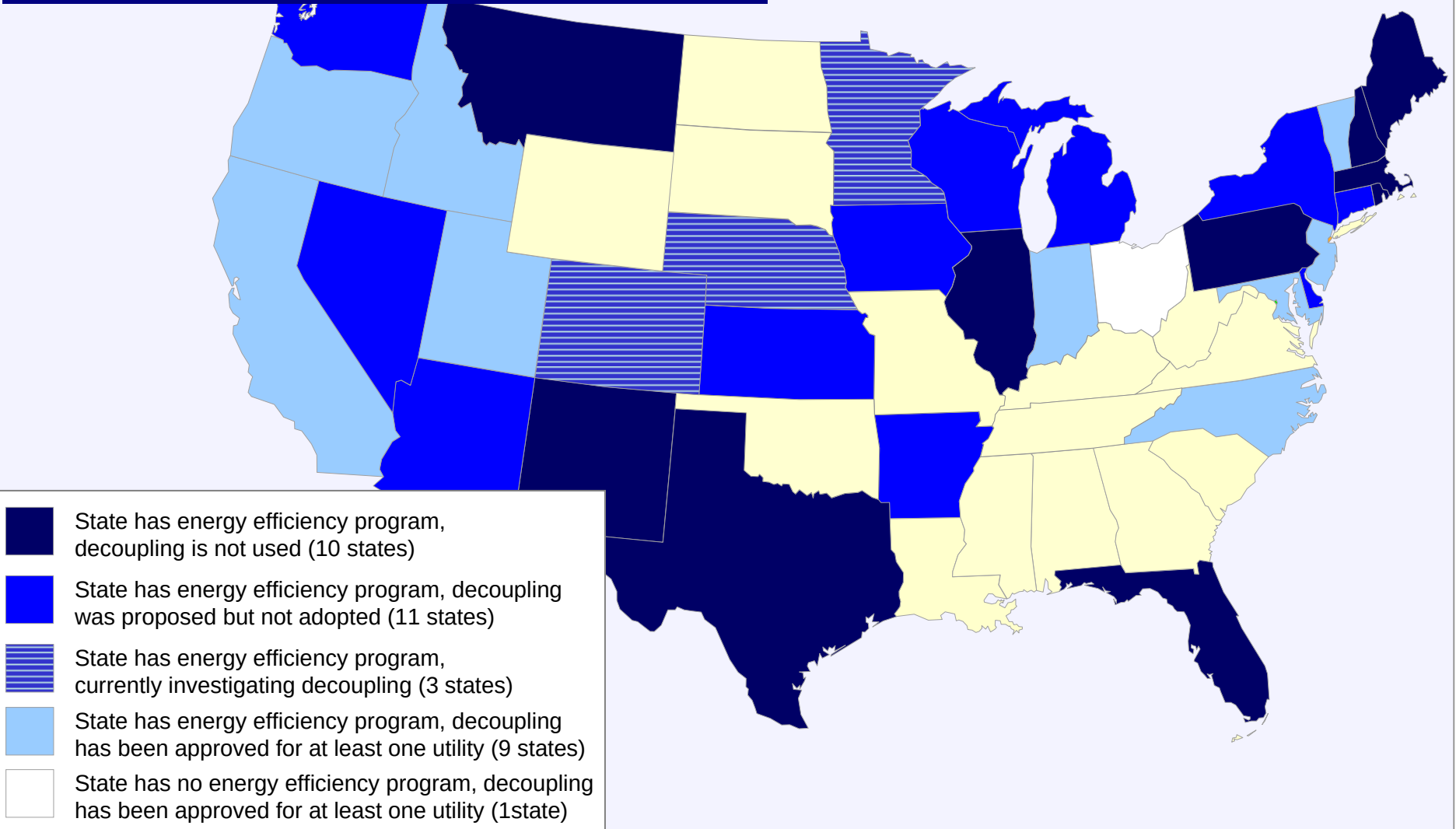
	Test Year	Forecasted Allowed
January	\$ 24.61	\$ 22.81
February	\$ 23.02	\$ 21.33
March	\$ 18.47	\$ 17.12
April	\$ 20.84	\$ 19.32
May	\$ 22.85	\$ 21.18
June	\$ 22.31	\$ 20.68
July	\$ 19.72	\$ 18.28
August	\$ 21.09	\$ 19.55
September	\$ 25.95	\$ 24.05
October	\$ 27.02	\$ 25.05
November	\$ 17.58	\$ 16.29
December	\$ 26.25	\$ 24.33
Total	\$ 269.71	\$ 250.00

Revenue Decoupling Tariff Example for January 2006

Allowed DNG Revenue per Customer	\$ 22.81
Actual Customers	610,000
Allowed DNG Revenue for Month	\$13,914,900
Actual DNG Revenue for Month	\$13,650,000
CET Monthly Accrual to Balancing Account	\$264,100
Accrual Added to Monthly Bill	\$0.433
New Monthly Charge	\$23.24

States with Energy Efficiency Programs – Decoupling Status (Gas & Electric)

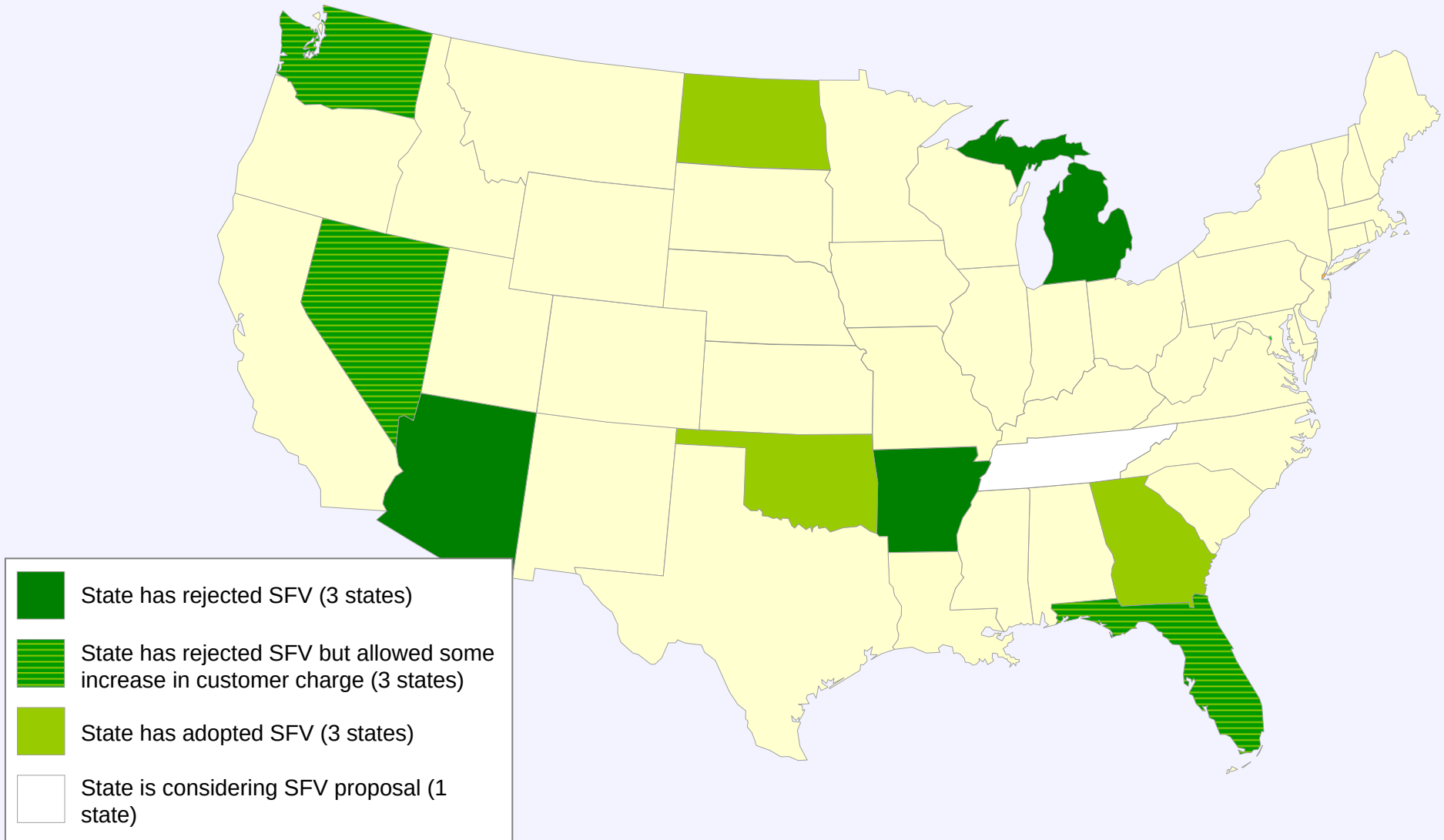
Utah Committee of Consumer Services
Witness: David Dismukes
Docket No. 05-057-T01
CCS Exhibit 1.2



Note: In Connecticut, the electric utilities do not have decoupling, but two natural gas LDCs have a partial decoupling mechanism in connection with their energy efficiency programs for low-income customers (a conservation adjustment mechanism). Washington has utilities with decoupling, but rejected the most recent utility proposal (January 2007). In Michigan, revenue decoupling was proposed by the Michigan Staff but opposed by the Michigan AG. The MPSC approved a stipulation that excluded revenue decoupling. In Kansas, revenue decoupling was proposed by Aquila. The parties involved agreed to a stipulation that excluded revenue decoupling while the Commission investigates it further in a general docket.

States that have Considered SFV

Utah Committee of Consumer Services
Witness: David Dismukes
Docket No. 05-057-T01
CCS Exhibit 1.3



Note: In Michigan, SFV was proposed by SEMCO Energy but opposed by the Michigan AG. The MPSC approved a stipulation that excluded SFV .

Information on Comprehensive DSM Programs Implemented by Ten Gas Utilities in 2004

Utah Committee of Consumer Services
Witness: David Dismukes
Docket No. 05-057-T01
CCS Exhibit 1.4

	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: Direct Testimony of Howard Geller on behalf of Southwest Energy Efficiency Project and Utah Clean Energy, January 23, 2006.

Prior Recommendations on ROE Adjustments For Revenue Neutrality Mechanisms

Jurisdiction	Company	Docket/Case	Proposed Change to Rate Structure	Cost of Capital Proposal	Adjustment
Arkansas	CenterPoint Energy Arkla	Docket No. 04-121-U	Load Change Adjustment Rider	Staff, Commercial Energy Users Group, Attorney General, and Arkansas Gas Consumers argue that, if Arkla proposed riders RSP, LCA, and ICR are approved, Arkla's risk would be reduced, and that a concomitant reduction in Arkla's cost of equity would be warranted.	primary recommendation is to reject riders, no specific numeric adjustment is provided.
Arkansas	CenterPoint Energy Arkla	Docket No. 04-121-U	Load Change Adjustment Rider	Attorney General witness W.B. Marcus states, "... recognizing that I already included a small risk-reducing impact of the existing weather normalization mechanism in my estimated rate of return, I would recommend a further 35-basis point adjustment for risk if the LCA were adopted."	0.35 adjustment to rate of return
Arizona	Southwest Gas	Docket No. G-01551A-04-0876	Conservation Margin Tracker	Southwest Gas recommends that the Commission determine the Company's cost of common equity to be 11.42 percent if its proposed conservation margin tracker ("CMT") is not adopted and 11.17 percent with adoption of the CMT. The Company's cost of capital recommendation is 9.4 percent without the CMT and 9.29 percent with the CMT	0.25 reduction to cost of equity; 0.11 reduction to cost of capital
Colorado	Public Service Company of Colorado	Docket No. 05S-264G	Service and Facilities Charge	Staff witness, Trogonoski's "range for ROE was 8.75% to 9.50%. His recommendation for an ROE of 9.50% was contingent on the Commission rejecting the Company's proposal to increase the Service and Facilities Charge. If the Commission allowed the Company's proposal, then Staff would recommend an ROE of 9.25%."	0.25 reduction to cost of equity

Jurisdiction	Company	Docket/Case	Proposed Change to Rate Structure	Cost of Capital Proposal	Adjustment
Delaware	Delmarva Power & Light Company	Docket No. 06-284	Bill Stabilization Adjustment	Delmarva witness Roger Morin recommends "the adoption of an overall return on investment of 8.08% and a rate of return on common equity of 11.0% on DP&L's natural gas delivery operations, assuming that the Bill Stabilization Adjustment ("BSA") is adopted. If the BSA adopted is not approved, I recommend the adoption of an overall return on investment of 8.20% and a rate of return on common equity of 11.25% on DP&L's natural gas delivery operations."	0.25 reduction to cost of equity; 0.12 reduction to cost of capital
Federal Energy Regulatory Commission	Texas Eastern Transmission Corporation	Docket No. CP87-312-008	Straight Fixed Variable	Texas Eastern challenges the Commission's decision to reduce the return on equity by 25 basis points. Texas Eastern submits that here the Commission failed to consider factors such as capital structure, service profile, competitive risks, operational risk, etc., in computing the appropriate return on equity. The Commission response explains that "[t]raditional MFV rate design places a pipeline's return on equity and the taxes related to that return, which are fixed costs, in the commodity component of rates. If service is not used at the level projected by the Commission, these fixed costs will not be recovered. Under a straight fixed-variable rate design, all fixed costs, including return and equity and related taxes, are included in the demand component of the rates. Thus, under an straight fixed-variable rate design the equity investor's assurance of recovery approaches that of a bondholder."	0.25 reduction to cost of equity
Federal Energy Regulatory Commission	Columbia Gas Transmission Corporation; Columbia Gulf Transmission Company	Docket Nos. RP91-161-011, RP92-3-000, RP90-108-016, RP91-82-008, and RS92-5-000 ; Docket Nos. RP91-160-000, RP92-2-000, RP90-107-013, and RS92-6-000	Straight Fixed Variable	The Cities believe that the failure to adjust the return on equity as a result of the change of rate design raises an issue of material fact, and that on cross examination they would have demonstrated that consistent with the Commission's determination in Transco, the returns on equity must be reduced to reflect the reduction of risk which accompanies the shift in rate design from MFV to SFV. Cities cites for example, Transcontinental Gas Pipe Line Corp., 56 FERC P61,037 (1991) (Transco), contending that the Commission imposed a 25 basis point reduction in the approved return on equity to reflect the possibility of lower risk.	0.25 reduction to cost of equity

Jurisdiction	Company	Docket/Case	Proposed Change to Rate Structure	Cost of Capital Proposal	Adjustment
Kansas	Aquila, Inc	Docket No. 07-AQLG-431-RTS	Decoupling Mechanism	Citizen's Utility Ratepayer Board witness Andrea C. Crane stated "[i]f the KCC approves a rate design that significantly reduces the Company's risk, then a reduction to return on equity would be appropriate. If all revenue risk is eliminated, then return on equity should be reduced by 50% of the difference between my recommended cost of equity of 9.35% and the Company's cost of debt of 7.13%."	1.10 reduction to cost of equity
Maryland	Baltimore Gas & Electric	Case 9036	Decoupling Mechanism	The Commission required a 50 basis point reduction in return on equity in conjunction with its approval of decoupling (Rider 8) for Baltimore Gas & Electric (BGE). This finding was later reversed.	0.50 reduction to cost of equity
Nevada	Southwest Gas	Docket No. 04-3011	Margin per Customer Balancing Provision	Southwest's witness, Frank J. Hanley, "...recommends an 11.75 percent cost of common equity, which recognizes Southwest is riskier than other relatively comparable local distribution companies. However, he states, if the Commission approves the proposed Margin per Customer Balancing Provision, he recommends the common equity cost rate be reduced by 25 basis points to 11.50 percent."	0.25 reduction to cost of equity
Tennessee	Chattanooga Gas	Docket No. 06-00175	Conservation and Usage Adjustment	Chattanooga witness, Dr. Roger A. Morin concluded that "a just and reasonable return on common equity ("ROE") for CGC at this time is 11.5%. If the Company's proposed Conservation and Usage Adjustment rider (CUA) and Pipeline Replacement Program (PRP) mechanism are approved, it is my opinion that a just and reasonable ROE for CGC is 11.0%."	0.50 reduction to cost of equity
United States Court of Appeals for the District of Columbia Circuit	United Distribution Companies, Petitioner v. Federal Energy Regulatory Commission, Respondent	No. 92-1485	Order 636 SFV Rate Design	"The PUCs argue that FERC should have reduced the pipelines' rate of return because the pipelines will be able to recover all of their fixed costs and return on investment through demand and reservation charges instead of facing the uncertainty of recovering a portion of their fixed costs and return through gas sales throughout the year. ...Specifically, the PUCs contend that FERC should have followed its decision in Transcontinental Gas Pipe Line Corp., ...and imposed a 25 basis point reduction in pipelines' return on equity to reflect the lower risk under SFV rate design. "	0.25 reduction to cost of equity

Jurisdiction	Company	Docket/Case	Proposed Change to Rate Structure	Cost of Capital Proposal	Adjustment
Vermont	Green Mountain Power Corporation	Docket No. 7175; Docket No. 7176	Alternative Regulation Plan	Green Mountain Power and the Department of Public Service signed a Memorandum of Understanding agreeing that GMP's Plan "provides for regular (quarterly) rate adjustments to flow through to ratepayers increases or decreases in power costs (which make up the majority of GMP's total costs). This has the effect of shifting risk associated with varying power costs to ratepayers; in recognition of this risk shift, the Plan provides a lower return on equity."	0.50 reduction to cost of equity

DSM Savings as Share of Total Sales

Utah Committee of Consumer Services
 Witness: David Dismukes
 Docket No. 05-057-T01
 CCS Exhibit 1.6

	Estimated Natural Gas Savings			Estimated Natural Gas Savings as a Percent of GS1 Sales		
	Year 1	Year 2	Year 3	Year 1	Year 2	Year 3
	----- (Dth) -----	----- (Dth) -----	----- (Dth) -----	----- (%) -----	----- (%) -----	----- (%) -----
Residential						
Residential Appliance Program	56,183	56,183	56,183	0.063%	0.062%	0.061%
ENERGY STAR® New Homes Program	81,095	81,095	81,095	0.091%	0.090%	0.088%
Residential Home Energy Audit and Weatherization Program	12,989	18,108	19,364	0.015%	0.020%	0.021%
Commercial						
Commercial Rebate Program	13,234	26,107	33,090	0.015%	0.029%	0.036%
Total Estimated Savings	163,501	181,493	189,731	0.184%	0.200%	0.205%

Note: Assumes annual increase in GS1 sales volumes of 2.0 percent.

DSM Participation as Share of Total Customers

Utah Committee of Consumer Services
 Witness: David Dismukes
 Docket No. 05-057-T01
 CCS Exhibit 1.7

	Estimated DSM Participation			Estimated Participation as a Percent of GS1 Customers		
	Year 1	Year 2	Year 3	Year 1	Year 2	Year 3
	----- (Dth) -----	----- (Dth) -----	----- (Dth) -----	----- (%) -----	----- (%) -----	----- (%) -----
Residential						
Residential Appliance Program	15,499	15,499	15,499	1.944%	1.882%	1.821%
ENERGY STAR® New Homes Program	8,605	8,605	8,605	1.079%	1.045%	1.011%
Residential Home Energy Audit and Weatherization Program	4,881	6,636	6,838	0.061%	0.107%	0.804%
Commercial						
Commercial Rebate Program	487	884	1,099	3.697%	3.840%	0.129%
Total Estimated Participation	29,472	31,624	32,041	3.697%	3.840%	3.766%

Note: Assumes annual increase in GS1 customers of 3.3 percent.

DSM Lost Revenue as Share of Total Revenues

Utah Committee of Consumer Services
 Witness: David Dismukes
 Docket No. 05-057-T01
 CCS Exhibit 1.8

	Estimated Lost Revenue			Estimated Lost Revenue as a Percent of GS1 Revenue		
	Year 1	Year 2	Year 3	Year 1	Year 2	Year 3
	----- (\$)	----- (\$)	----- (\$)	----- (%)	----- (%)	----- (%)
Residential						
Residential Appliance Program	\$ 99,148	\$ 99,148	\$ 99,148	0.05%	0.04%	0.04%
ENERGY STAR® New Homes Program	\$ 143,112	\$ 143,112	\$ 143,112	0.07%	0.06%	0.06%
Residential Home Energy Audit and Weatherization Program	\$ 22,923	\$ 31,957	\$ 34,172	0.01%	0.01%	0.01%
Commercial						
Commercial Rebate Program	\$ 23,355	\$ 46,073	\$ 58,394	0.01%	0.02%	0.03%
Total Estimated Lost Revenue	\$ 288,537	\$ 320,289	\$ 334,826	0.13%	0.14%	0.14%

Note: Assumes annual increase in GS1 revenues of 3.2 percent. Lost revenues are valued at \$1.76/Dth.

Financial Impact of Net Lost Revenues

Utah Committee of Consumer Services
 Witness: David Dismukes
 Docket No. 05-057-T01
 CCS Exhibit 1.9

	Change in Revenue			Income Impact			Shareholders Equity	Impact on ROE
	Use per Customer	DSM	New Customers	Use per Customer	DSM	New Customers		
2007	\$(1,971,361)	\$ (288,537)	\$ 7,052,203	\$(1,221,185)	\$ (178,738)	\$ 4,368,579	\$ 313,071,056	0.95%
2008	\$(2,905,519)	\$ (608,826)	\$ 6,391,367	\$(1,799,862)	\$ (377,145)	\$ 3,959,215	\$ 339,501,229	0.52%
2009	\$(4,485,340)	\$ (943,652)	\$ 6,213,829	\$(2,778,502)	\$ (584,557)	\$ 3,849,237	\$ 363,965,179	0.13%
Total	\$(9,362,220)	\$(1,841,015)	\$ 19,657,399	\$(5,799,549)	\$(1,140,440)	\$ 12,177,031		1.61%
Net Impact:							\$ 5,237,041.80	

Note: Revenue impacts are valued at \$1.76/Dth for DSM and use per customer. Revenue impacts for new customers are valued at \$2.47/Dth; a figure calculated using 2006 total GS1 revenue divided by 2006 GS1 usage.

Impact of Sales on Utility Earnings – Adjustment

Utah Committee of Consumer Services
Witness: David Dismukes
Docket No. 05-057-T01
CCS Exhibit 1.10

Changes in total usage can be decomposed between:

Usage attributable to a
change in use per customer
(existing customers)

Usage attributable to
growth in new
customers

$$\Delta Q_t = \left(\frac{Q_t}{C_t} - \frac{Q_{t-1}}{C_{t-1}} \right) \times C_{t-1} + \left(\frac{Q_t}{C_t} \right) \times C_t - C_{t-1}$$

Where:

C = customers

C_{t-1} = prior period customers

C_t = current period customers

Q_t/C_t = current period use per customer

Q_{t-1}/C_{t-1} = prior period use per customer

Estimated Impacts on Usage – Changes in Use per Customer and Changes in Customer Growth

Utah Committee of Consumer Services
Witness: David Dismukes
Docket No. 05-057-T01
CCS Exhibit 1.11

	Average Number of Customers GS1	GS1 Usage per Customer (Dth/Cust)	Temperature Adjusted GS1 Usage (Dth)	Change in Use -- Decreased Average Use Existing Customers (Dth)	Change in Use -- Increased Number of New Customer (Dth)	Net Change (Dth)
2001	677,423	118.97	80,593,150			
2002	695,399	115.84	80,555,994	(2,119,521)	2,082,365	(37,156)
2003	724,006	118.90	86,083,445	2,126,113	3,401,338	5,527,451
2004	747,066	114.10	85,242,116	(3,472,533)	2,631,204	(841,328)
2005	778,414	112.88	87,864,443	(916,118)	3,538,444	2,622,326
2006	797,215	111.40	88,810,678	(1,148,163)	2,094,399	946,235
					Net Period Change	8,217,528
					Total Decrease	(878,484)
					Total Increase	9,096,013
					Net Period Change	8,217,528
					Average Period Change	1,643,506

Estimated Impacts on Revenue – Changes in Use per Customer and Changes in Customer Growth

Utah Committee of Consumer Services
 Witness: David Dismukes
 Docket No. 05-057-T01
 CCS Exhibit 1.12

	Average Number of Customers GS1	GS1 Usage per Customer (Dth/Cust)	Temperature Adjusted GS1 Usage (Dth)	Revenue Impact		
				Use per Customer -----	Customers (\$)	Total -----
2001	677,423	118.97	80,593,150			
2002	695,399	115.84	80,555,994	\$ (2,809,677)	\$ 4,901,965	\$ 2,092,288
2003	724,006	118.90	86,083,445	\$ 9,594,665	\$ 8,195,686	\$ 17,790,351
2004	747,066	114.10	85,242,116	\$ (2,098,515)	\$ 6,539,675	\$ 4,441,159
2005	778,414	112.88	87,864,443	\$ (4,623,071)	\$ 8,696,110	\$ 4,073,039
2006	797,215	111.40	88,810,678	\$ (2,110,924)	\$ 5,164,380	\$ 3,053,456

Summary Financial Impact of Changes in Use per Customer and Customers, 2001-2006

Utah Committee of Consumer Services
Witness: David Dismukes
Docket No. 05-057-T01
CCS Exhibit 1.13
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	2001	2002	2003	2004	2005	2006
<u>Return on Equity</u>						
Allowed ROE	11.00%	11.00%	11.20%	11.20%	11.20%	11.20%
ROE Impact of Change in Use per Customer	0.00%	-0.60%	1.99%	-0.41%	-0.87%	-0.41%
ROE Impact Change in Customers	0.00%	1.04%	1.66%	1.17%	1.51%	1.51%
ROE Impact Change in Expenses Rate Base and Capital Elements	-0.54%	-2.38%	-3.76%	-1.92%	-1.16%	-2.08%
Actual Achieved ROE	10.46%	9.06%	11.09%	10.05%	10.68%	10.22%

Financial Impact of Change in Use per Customer, 2001-2006

Description	Utah Jurisdiction DNG Related					
	2001	2002	2003	2004	2005	2006
Utility Operating DNG Revenue						
System Distribution Non-Gas Revenue	\$ 200,696,764	\$ 204,279,049	\$ 218,434,068	\$ 224,782,962	\$ 228,246,882	\$ 218,989,828
General Related Other Revenue	11,123,598	11,443,447	5,130,380	5,177,571	6,535,759	\$ 6,913,523
	\$ 211,820,362	\$ 215,722,496	\$ 223,564,448	\$ 229,960,533	\$ 234,782,641	\$ 225,903,351
Revenue Impact Declining Usage	\$ -	\$ (2,809,677)	\$ 9,594,665	\$ (2,098,515)	\$ (4,623,071)	\$ (2,110,924)
Utility Operating Expenses						
<u>Gas Purchase Expenses</u>						
Utah Gathering & CO2	\$ 12,006,619	\$ 12,622,788	\$ 8,298,154	\$ 8,977,154	\$ 8,460,107	\$ -
Total Gathering & CO2	\$ 12,006,619	\$ 12,622,788	\$ 8,298,154	\$ 8,977,154	\$ 8,460,107	\$ -
<u>Operation and Maintenance Expenses</u>						
Production	\$ (1,214,912)	\$ (745,152)	\$ (1,010,739)	\$ (1,203,294)	\$ (1,352,503)	\$ (1,691,906)
Distribution	30,365,590	37,720,970	39,644,134	36,869,734	40,254,743	44,593,770
Customer Accounts	14,255,577	15,232,585	26,204,678	23,751,948	22,384,076	21,952,512
Customer Service & Information	2,013,500	1,860,122	2,445,531	2,443,979	2,288,424	2,430,687
Administrative & General (1)	48,294,087	38,236,483	26,152,843	35,666,505	33,127,149	40,068,201
Total O&M Expense	\$ 93,713,842	\$ 92,305,008	\$ 93,436,447	\$ 97,528,872	\$ 96,701,888	\$ 107,353,264
<u>Other Operating Expenses</u>						
Depreciation, Depletion, Amortization	\$ 34,548,652	\$ 38,409,553	\$ 38,687,066	\$ 41,599,371	\$ 44,205,272	\$ 35,729,146
Taxes Other Than Income Taxes	8,895,086	8,983,426	9,409,773	9,417,462	10,667,038	11,238,606
Income Taxes	17,089,113	14,906,109	23,521,025	19,219,402	19,638,723	19,805,848
South Georgia Amortization	1,407,363	1,431,437	1,435,745	-	-	-
Section 29 Tax Credits	(2,650,483)	-	224	-	-	-
Total Other Operating Expenses	\$ 59,289,732	\$ 63,730,526	\$ 73,053,834	\$ 70,236,235	\$ 74,511,034	\$ 66,773,600
Total Utility Operating Expenses	\$ 165,010,193	\$ 168,658,322	\$ 174,788,434	\$ 176,742,261	\$ 179,673,028	\$ 174,126,864
NET OPERATING INCOME	\$ 46,810,169	\$ 44,254,496	\$ 58,370,678	\$ 51,119,757	\$ 50,486,541	\$ 49,665,563
TOTAL RATE BASE	\$ 505,674,144	\$ 539,520,097	\$ 549,428,512	\$ 600,068,706	\$ 595,177,075	\$ 601,477,213
Adjusted Return on Rate Base	9.26%	8.20%	10.62%	8.52%	8.48%	8.26%
Adjusted Return on Equity	10.46%	8.46%	13.08%	9.64%	9.81%	9.81%
Actual Return on Rate Base	9.26%	8.52%	9.55%	8.73%	8.96%	8.47%
Actual Return on Equity	10.46%	9.06%	11.09%	10.05%	10.68%	10.22%
Incremental Impact Return on Rate Base	0.00%	-0.32%	1.07%	-0.22%	-0.48%	-0.22%
Incremental Impact Return on Equity	0.00%	-0.60%	1.99%	-0.41%	-0.87%	-0.41%

Financial Impact of Change in Customers, 2001-2006

Utah Committee of Consumer Services

Witness: David Dismukes

Docket No. 05-057-T01

CCS Exhibit 1.13

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Description	Utah Jurisdiction DNG Related					
	2001	2002	2003	2004	2005	2006
Utility Operating DNG Revenue						
System Distribution Non-Gas Revenue	\$ 200,696,764	\$ 204,279,049	\$ 218,434,068	\$ 224,782,962	\$ 228,246,882	218,989,828
General Related Other Revenue	11,123,598	11,443,447	5,130,380	5,177,571	6,535,759	6,913,523
	<u>\$ 211,820,362</u>	<u>\$ 215,722,496</u>	<u>\$ 223,564,448</u>	<u>\$ 229,960,533</u>	<u>\$ 234,782,641</u>	<u>\$ 225,903,351</u>
Revenue Impact Customer Growth	-	\$ 4,901,965	\$ 8,195,686	\$ 6,539,675	\$ 8,696,110	\$ 5,164,380
Utility Operating Expenses						
<u>Gas Purchase Expenses</u>						
Utah Gathering & CO2	\$ 12,006,619	\$ 12,622,788	\$ 8,298,154	\$ 8,977,154	\$ 8,460,107	\$ -
Total Gathering & CO2	<u>\$ 12,006,619</u>	<u>\$ 12,622,788</u>	<u>\$ 8,298,154</u>	<u>\$ 8,977,154</u>	<u>\$ 8,460,107</u>	<u>\$ -</u>
<u>Operation and Maintenance Expenses</u>						
Production	\$ (1,214,912)	\$ (745,152)	\$ (1,010,739)	\$ (1,203,294)	\$ (1,352,503)	(1,691,906)
Distribution	30,365,590	37,720,970	39,644,134	36,869,734	40,254,743	44,593,770
Customer Accounts	14,255,577	15,232,585	26,204,678	23,751,948	22,384,076	21,952,512
Customer Service & Information	2,013,500	1,860,122	2,445,531	2,443,979	2,288,424	2,430,687
Administrative & General	48,294,087	38,318,997	26,143,750	35,726,973	33,232,370	40,084,877
Total O&M Expense	<u>\$ 93,713,842</u>	<u>\$ 92,387,523</u>	<u>\$ 93,427,354</u>	<u>\$ 97,589,339</u>	<u>\$ 96,807,109</u>	<u>\$ 107,369,940</u>
<u>Other Operating Expenses</u>						
Depreciation, Depletion, Amortization	\$ 34,548,652	\$ 38,409,553	\$ 38,687,066	\$ 41,599,371	\$ 44,205,272	\$ 35,729,146
Taxes Other Than Income Taxes	8,895,086	8,983,426	9,409,773	9,417,462	10,667,038	11,238,606
Income Taxes	17,089,113	17,808,596	22,992,122	22,483,542	24,667,124	20,602,475
South Georgia Amortization	1,407,363	1,431,437	1,435,745	-	-	0
Section 29 Tax Credits	(2,650,483)	-	224	-	-	0
Total Other Operating Expenses	<u>\$ 59,289,732</u>	<u>\$ 66,633,012</u>	<u>\$ 72,524,931</u>	<u>\$ 73,500,376</u>	<u>\$ 79,539,434</u>	<u>\$ 67,570,227</u>
Total Utility Operating Expenses	<u>\$ 165,010,193</u>	<u>\$ 171,643,323</u>	<u>\$ 174,250,439</u>	<u>\$ 180,066,869</u>	<u>\$ 184,806,650</u>	<u>\$ 174,940,167</u>
NET OPERATING INCOME	<u>\$ 46,810,169</u>	<u>\$ 48,981,138</u>	<u>\$ 57,509,696</u>	<u>\$ 56,433,339</u>	<u>\$ 58,672,100</u>	<u>\$ 56,127,564</u>
TOTAL RATE BASE	<u>\$ 505,674,144</u>	<u>\$ 539,520,097</u>	<u>\$ 549,428,512</u>	<u>\$ 600,068,706</u>	<u>\$ 595,177,075</u>	<u>601,477,213</u>
Adjusted Return on Rate Base	9.26%	9.08%	10.47%	9.40%	9.86%	9.33%
Adjusted Return on Equity	10.46%	10.10%	12.76%	11.22%	12.19%	11.73%
Actual Return on Rate Base	9.26%	8.52%	9.55%	8.73%	8.96%	8.47%
Actual Return on Equity	10.46%	9.06%	11.09%	10.05%	10.68%	10.22%
Incremental Impact Return on Rate Base	0.00%	0.56%	0.92%	0.67%	0.90%	0.86%
Incremental Impact Return on Equity	0.00%	1.04%	1.66%	1.17%	1.51%	1.51%
Allowed Return on Equity	11.00%	11.00%	11.20%	11.20%	11.20%	11.20%

Questar Average and Incremental Investment Trends

Utah Committee of Consumer Services
 Witness: David Dismukes
 Docket No. 05-057-T01
 CCS Exhibit 1.14

Description	2001	2002	DNG Related		2005	2006
			2003	2004		
Rate Base	\$ 505,674,144	\$ 539,520,097	\$ 549,428,512	\$ 600,068,706	\$ 595,177,075	\$ 601,477,213
Change in Rate Base		\$ 33,845,953	\$ 9,908,416	\$ 50,640,194	\$ (4,891,631)	\$ 6,300,138
Average Customers	694,363	712,651	731,752	754,960	786,740	823,916
Change in Customers		18,288	19,101	23,208	31,780	37,176
Incremental Rate Base Cost Per Customer		\$ 1,851	\$ 519	\$ 2,182	\$ (154)	\$ 169
Average Rate Base Cost per Customer	\$ 728	\$ 757	\$ 751	\$ 795	\$ 757	\$ 730
Net Utility Plant in Service	\$ 580,037,119	\$ 620,793,377	\$ 650,036,512	\$ 705,080,214	\$ 719,756,346	740,424,646
Change in Net Utility Plant in Service		40,756,258	29,243,135	55,043,702	14,676,132	20,668,300
Average Customers	694,363	712,651	731,752	754,960	786,740	823,916
Change in Customers		18,288	19,101	23,208	31,780	37,176
Incremental Net Utility Plant Cost Per Customer		\$ 2,229	\$ 1,531	\$ 2,372	\$ 462	\$ 556
Average Net Utility Plant Cost per Customer	\$ 835	\$ 871	\$ 888	\$ 934	\$ 915	\$ 899

Example of Revenue Decoupling - Corrected

Utah Committee of Consumer Services
 Witness: David Dismukes
 Docket No. 05-057-T01
 CCS Exhibit 1.15

Revenue Decoupling Tariff Example for January 2006	
Allowed DNG Revenue per Customer	\$ 22.81
Actual Customers	610,000
Allowed DNG Revenue for Month	\$13,914,900
Actual DNG Revenue for Month	\$13,650,000
CET Monthly Accrual to Balancing Account	\$264,100
Accrual Added to Monthly Bill	\$0.433
New Monthly Charge	\$23.24

Revenue Decoupling Tariff Example for January 2006	
Allowed DNG Revenue per Customer	\$ 22.81
Actual Customers	600,000
Allowed DNG Revenue for Month	\$13,686,000
Actual DNG Revenue for Month	\$13,650,000
CET Monthly Accrual to Balancing Account	\$36,000
Accrual Added to Monthly Bill	\$0.06
New Monthly Charge	\$22.87

Overview of Third-Party Administrators

Utah Committee of Consumer Services
Witness: David Dismukes
Docket No. 05-057-T01
CCS Exhibit 1.16

State

Overview

Maine

The public benefits program operated by the PUC is known as Efficiency Maine. By statute, at least 20% of funds must support energy programs for low-income residents, and at least 20% of funds must support energy programs for small business customers. The PUC assesses utilities to collect funds for energy programs and administrative costs.

New Jersey

In 1999, electric-utility restructuring legislation created a "societal benefits charge" to support investments in energy efficiency and renewable energy. The SBC funds New Jersey's Clean Energy Program, administered by the New Jersey BPU. The NJCEP provides technical and financial assistance, information and education for all classes of ratepayers. NJCEP energy-efficiency and renewable-energy programs were initially managed and implemented by the state's IOUs and LDCs, but these are being transferred to a third-party program manager. The BPU will act as the administrator of the NJCEP, while contracted program managers will be responsible for managing and implementing these programs.

Ohio

The Energy Loan Fund provides incentives for energy efficiency, distributed energy and renewable-energy projects. The ELF will collect \$100 million over 10 years from Ohio's four investor-owned utilities to provide low-interest loans for energy-efficiency improvements at residential, government, educational, commercial, industrial and agricultural facilities. It also provides funding for renewable-energy projects. The Ohio Department of Development's Office of Energy Efficiency operates the fund.

Oregon

In 2002 the Oregon PUC authorized the Energy Trust of Oregon (independent non-profit), to administer the utility's renewable energy and energy efficiency projects. Of the funds collected, 67% must be allocated towards energy efficiency programs and 17% to renewables. The remaining support low-income housing energy assistance and school energy-conservation efforts. In addition, the Energy Trust administers gas conservation programs for residential and commercial customers of Northwest Natural and Cascade Natural Gas Corporation, and select programs for residential customers of Avista Corporation.

Revenue Impact of Test Year Repression Adjustment Example

Utah Committee of Consumer Services
Witness: David Dismukes
Docket No. 05-057-T01
CCS Exhibit 1.17

		Repression Analysis for GS-1	
		5-Year Average	3-Year Average
1	Repression Impact per Residential Customer (Dth)	(1.52)	(0.99)
2	Residential Sales (Dth)	\$ 88,692,051	\$ 88,692,051
3	Residential Customers	785,746	785,746
4	Residential Sales Impact of Repression (Dth)	(1,197,077)	(776,622)
5	Residential Non-Gas Revenue	\$ 215,936,372	\$ 215,936,372
6	Customer Charge	\$ (3,928,730)	\$ (3,928,730)
7	Res Non-Gas Revenue Less Customer Charge	\$ 212,007,642	\$ 212,007,642
8	Res Non-Gas Revenue Per Dth	\$ 2.39	\$ 2.39
9	Revenue Impact of Repression	\$ (2,861,468)	\$ (1,856,421)
10	Uncollectibles	\$ 12,276	\$ 7,964
11	Net Revenue Impact of Repression	\$ (2,873,744)	\$ (1,864,385)
12	Combined Tax Rate	36.2%	36.2%
13	Combined Taxes	\$ 1,041,157	\$ 675,467
14	Net Operating Income Impact of Repression	\$ (1,832,586)	\$ (1,188,918)

Note: Assumes a customer charge of \$5.00. The source of this is the current GS-1 tariff at: <http://www.questargas.com/Tariffs/uttariff.pdf>.
Assumes an uncollectible rate of 0.4 percent.